

AEP East Companies  
 Transmission Cost of Service Formula Rate  
 Utilizing Historic Cost Data for 2009 and Projected Net Plant at Year-End 2010

**KENTUCKY POWER COMPANY**

Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(ln 138)			\$41,178,105
2	REVENUE CREDITS	(Note A) (Worksheet E)	2,434,307	DA 1.00000	\$ 2,434,307
3	REVENUE REQUIREMENT For All Company Facilities	(ln 1 less ln 2)			<u>\$ 38,743,798</u>

**MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.**

4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet J)		-	DA 1.00000	\$ -
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				
6	Annual Rate	$(\ln 1 - \ln 105 - \ln 106) / ((\ln 48 + \ln 49 + \ln 50 + \ln 51 + \ln 53) \times 100)$			16.28%
7	Monthly Rate	(ln 6 / 12)			1.36%
8	NET PLANT CARRYING CHARGE ON LINE 6, w/o depreciation or ROE incentives (Note B)				
9	Annual Rate	$(\ln 1 - \ln 105 - \ln 106 - \ln 111 - \ln 112) / ((\ln 48 + \ln 49 + \ln 50 + \ln 51 + \ln 53) \times 100)$			13.83%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)				
11	Annual Rate	$(\ln 1 - \ln 105 - \ln 106 - \ln 111 - \ln 112 - \ln 133 - \ln 134) / ((\ln 48 + \ln 49 + \ln 50 + \ln 51 + \ln 53) \times 100)$			3.70%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet J)				-
13	<b>REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES</b>				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below			2,102,150
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				1,089,485
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				205,436
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			<u>807,229</u>

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Line No.	(1)	(2)	(3)	(4)	(5)
	<b>RATE BASE CALCULATION</b>	<b>Data Sources (See "General Notes")</b>	<b>TO Total NOTE C</b>	<b>Allocator</b>	<b>Total Transmission</b>
18	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.C)	540,095,917	NA 0.00000	0
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	-3,337,422	NA 0.00000	0
20	Transmission	(Worksheet A In 3.C & Ln 142)	438,744,866	DA	437,139,495
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 143)	0	TP 0.99634	0
22	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.D)		18,840,335	DA 1.00000	18,840,335
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I, In 22.D)		0	DA 1.00000	0
24	Distribution	(Worksheet A In 5.C)	568,761,740	NA 0.00000	0
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	0	NA 0.00000	0
26	General Plant	(Worksheet A In 7.C)	33,960,860	W/S 0.08595	2,918,823
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	0	W/S 0.08595	0
28	Intangible Plant	(Worksheet A In 9.C)	16,666,518	W/S 0.08595	1,432,432
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	1,613,732,814		460,331,086
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.C)	225,725,166	NA 0.00000	0
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	-357,559	NA 0.00000	0
33	Transmission	(Worksheet A In 14.C & 28.C)	141,779,874	TP1= 0.99589	141,197,813
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	0	TP1= 0.99589	0
35	Plus: Transmission Plant-in-Service Additions (Worksheet I, In 21.I)		127,664	DA 1.00000	127,664
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I In 24.D)		0	DA 1.00000	0
37	Plus: Additional Transmission Depreciation for 2010 (In 111)		7,420,678	TP1 0.99589	7,390,213
38	Plus: Additional General & Intangible Depreciation for 2010 (In 113 + In 114)		4,528,066	W/S 0.08595	389,172
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I In 23.D)		0	DA 1.00000	0
40	Distribution	(Worksheet A In 16.C)	139,979,041	NA 0.00000	0
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	0	NA 0.00000	0
42	General Plant	(Worksheet A In 18.C)	7,194,870	W/S 0.08595	618,375
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	0	W/S 0.08595	0
44	Intangible Plant	(Worksheet A In 20.C)	17,291,094	W/S 0.08595	1,486,112
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	543,688,894		151,209,350
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	311,390,888		0
48	Transmission	(In 20 + In 21 - In 33 - In 34)	296,964,992		295,941,682
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		18,712,671		18,712,671
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		0		0
51	Plus: Additional Transmission Depreciation for 2010 (-In 37)		(7,420,678)		(7,390,213)
52	Plus: Additional General & Intangible Depreciation for 2010 (-In 38)		(4,528,066)		(389,172)
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		0		0
54	Distribution	(In 24 + In 25 - In 40 - In 41)	428,782,699		0
55	General Plant	(In 26 + In 27 - In 42 - In 43)	26,765,990		2,300,448
56	Intangible Plant	(In 28 - In 44)	(624,576)		(53,680)
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	1,070,043,920		309,121,736
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(31,362,189)	NA	0
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(162,185,880)	DA	(46,357,239)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(21,654,672)	DA	(1,380,134)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	14,157,012	DA	3,460,421
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	0	DA	0
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(201,045,729)		(44,276,952)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	7,436,551	DA	30,592
66	REGULATORY ASSETS	(Worksheet A In 36. (C))	0	DA	0
67	WORKING CAPITAL	(Note E)			
68	Cash Working Capital	(1/8 * In 88)	617,192		614,934
69	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	103,391	TP 0.99634	103,013
70	A&G Materials & Supplies	(Worksheet C, In 3.(D))	119,885	W/S 0.08595	10,304
71	Stores Expense	(Worksheet C, In 4.(D))	0	GP(h) 0.27682	0
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	14,836,181	W/S 0.08595	1,275,121
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	922,254	GP(h) 0.27682	255,294
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	0	DA 1.00000	0
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(14,476,581)	NA 0.00000	0
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	2,122,322		2,258,665
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(236,193)	DA 1.00000	(236,193)
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		878,320,871		266,897,848

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Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
79	OPERATION & MAINTENANCE EXPENSE				
80	Production	321.80.b	457,856,290		
81	Distribution	322.156.b	29,693,612		
82	Customer Related Expense	322.164,171,178.b	8,740,355		
83	Regional Marketing Expenses	322.131.b	1,168,311		
84	Transmission	321.112.b	(821,880)		
85	TOTAL O&M EXPENSES	(sum lns 79 to 83)	496,636,688		
86	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	2,102,150		
87	Less: Account 565	(Note H) 321.96.b	(7,861,567)		
88	Less: State Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
	Total O&M Allocable to Transmission	(lns 83 - 85 - 86 - 87)	4,937,537	TP 0.99634	4,919,471
89	Administrative and General	323.197.b (Note J)	24,046,450		
90	Less: Acct. 924, Property Insurance	323.185.b	406,399		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	4,099,565		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(867,380)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	297,335		
94	Acct. 928, Reg. Com. Exp.	323.189.b	(496)		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	398,905		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	507,618		
97	Balance of A & G	(ln 89 - sum ln 90 to ln 96)	19,204,504	W/S 0.08595	1,650,564
98	Plus: Acct. 924, Property Insurance	(ln 90)	406,399	GP(h) 0.27682	112,497
99	Acct. 928 - Transmission Specific	#REF!	-	TP 0.99634	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F ln 29.(E) (Note L)	-	TP 0.99634	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F ln 35.(E) (Note L)	83,295	DA 1.00000	83,295
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,693,481	W/S 0.08595	231,496
103	A & G Subtotal	(sum lns 97 to 102)	22,387,679		2,077,852
104	O & M EXPENSE SUBTOTAL	(ln 88 + ln 103)	27,325,216		6,997,322
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	(8,835,297)	DA 1.00000	(8,835,297)
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA 1.00000	-
107	TOTAL O & M EXPENSE	(ln 104 + ln 105 + ln 106)	18,489,919		(1,837,975)
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	20,344,274	NA 0.00000	-
110	Distribution	336.8.f	19,366,762	NA 0.00000	-
111	Transmission	336.7.f	7,420,678	TP1 0.99589	7,390,213
112	Plus: Transmission Plant-in-Service Additions (Worksheet I ln 21.I)		127,664	DA 1.00000	127,664
113	General	336.10.f	802,099	W/S 0.08595	68,938
114	Intangible	336.1.f	3,725,967	W/S 0.08595	320,235
115	TOTAL DEPRECIATION AND AMORTIZATION	(lns 109+110+111 +112+113+114)	51,787,444		7,907,050
116	TAXES OTHER THAN INCOME	(Note N)			
117	Labor Related				
118	Payroll	Worksheet H ln 21.(D)	1,655,606	W/S 0.08595	142,294
119	Plant Related				
120	Property	Worksheet H ln 21.(C) & ln 35.(C)	9,619,712	DA	3,618,147
121	Gross Receipts/Sales & Use	Worksheet H ln 21.(F)	(371,606)	NA 0.00000	-
122	Other	Worksheet H ln 21.(E)	778,850	GP(h) 0.27682	215,598
123	TOTAL OTHER TAXES	(sum lns 118 to 122)	11,682,562		3,976,038
124	INCOME TAXES	(Note O)			
125	$T=1 - ((1 - \text{SIT}) * (1 - \text{FIT})) / (1 - \text{SIT} * \text{FIT} * p) =$		38.20%		
126	$\text{EIT}=(T/(1-T)) * (1-(\text{WCLTD}/\text{WACC})) =$		36.04%		
127	where WCLTD=(ln 162) and WACC = (ln 165)				
128	and FIT, SIT & p are as given in Note O.				
129	$\text{GRCF}=1 / (1 - T) =$ (from ln 125)		1.6182		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, ln 19.c)	(821,956)		
131	Income Tax Calculation	(ln 126 * ln 134)	27,461,205		8,344,714
132	ITC adjustment	(ln 129 * ln 130)	(1,330,123)	NP(h) 0.28044	(373,022)
133	TOTAL INCOME TAXES	(sum lns 131 to 132)	26,131,083		7,971,692
134	RETURN ON RATE BASE (Rate Base * WACC)	(ln 78 * ln 165)	76,193,067		23,153,003
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, ln 2.(B))		8,298	DA 1.00000	8,298
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, ln 4, Cols. ((F) & (H))		-		-
137	Tax Impact on (Gains) / Losses on Sales of Plant Held for Future Use (ln 136 * ln 126)		-		-
138	TOTAL REVENUE REQUIREMENT	(sum lns 107, 115, 123, 133, 134, 135, 136, 137)	184,292,372		41,178,105

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SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
139	Total transmission plant	(In 20)						438,744,866	
140	Less transmission plant excluded from PJM Tariff (Note P)							-	
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)							1,605,371	
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)						437,139,495	
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)						<b>TP</b>	<b>0.99634</b>
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)							
145	Production	354.20.b	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
146	Transmission	354.21.b	9,541,025	2,878,391	12,419,416	NA	0.00000	-	
147	Regional Market Expenses	354.22.b	1,320,732	1,123,582	2,444,314	TP	0.99634	2,435,370	
148	Distribution	354.23.b	0	0	-	NA	0.00000	-	
149	Other (Excludes A&G)	354.24,25,26.b	8,965,083	782,203	9,747,286	NA	0.00000	-	
150	Total	(sum Ins 145 to 149)	21,655,359	6,680,465	28,335,824	NA	0.00000	2,435,370	
151	Transmission related amount							<b>W/S=</b>	<b>0.08595</b>
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)								\$
153	Long Term Interest	(Worksheet L, In. 35, col. (D))						35,539,453	
154	Preferred Dividends	(Worksheet L, In. 40, col. (D))						-	
155	<u>Development of Common Stock:</u>								
156	Proprietary Capital	(FF1 p 112, Ln 16.c)						431,783,697	
157	Less: Preferred Stock	(FF1 p 112, Ln 3.c)						-	
158	Less: Account 216.1	(FF1 p 112, Ln 12.c)						-	
159	Less: Account 219	(FF1 p 112, Ln 15.c)						(600,942)	
160	Common Stock	(In 156 - In 157 - In 158 - In 159)						432,384,639	
161								Cost	
162	Long Term Debt (Note T) Worksheet L, In 35, col. (B))		\$	550,000,000	55.99%		(Note S)	0.0646	Weighted
163	Preferred Stock (In 157)			-	0.00%			-	0.0000
164	Common Stock (In 160)			432,384,639	44.01%			11.49%	0.0506
165	Total (Sum Ins 162 to 164)			982,384,639				<b>WACC=</b>	<b>0.0867</b>

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**Letter**

**Notes**

General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X

- A Revenue credits include:  
 1) Forfeited Discounts.  
 2) Miscellaneous Service Revenues.  
 3) Rental revenues earned on assets included in the rate base.  
 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.  
 5) Other electric revenues.  
 6) Revenues for grandfathered PTP contracts included in the load divisor.  
 See Worksheet E for details.
- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C Transmission Plant balances in this study are projected as of December 31, 2010. Other ratebase amounts are as of December 31, 2009.
- D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.  
**The company will not include the ADIT portion of deferred hedge gains and losses in rate base.**
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:  
 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancillary Services Revenue, as shown on line 85.  
 2) AEP transmission equalization transfers, as shown on line 86  
 3) The impact of state regulatory deferrals and amortizations, as shown on line 87  
 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- G **Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.**
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11. The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.  
**The company records referenced on lines 105 and 106 is the KENTUCKY POWER COMPANY general ledger.**
- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J **General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.**
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- L Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M **See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the seven operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula**
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT. A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f) (In 130) multiplied by (1/1-T) . If the applicable tax rates are zero enter 0.  
 Inputs Required: FIT = 35.00%  
 SIT= 4.93% (State Income Tax Rate or Composite SIT. Worksheet G)  
 p = 0.00% (percent of federal income tax deductible for state purposes)
- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership.  
**In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.**
- T This note only applies to Indiana Michigan Power Company.
- U **This note only applies to the true-up template.**

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**KENTUCKY POWER COMPANY**

Line No.			Total	Allocator	Transmission Amount
166	REVENUE REQUIREMENT (w/o incentives)	(In 303)			\$39,760,159
167	REVENUE CREDITS	(Note A) (Worksheet E)	2,434,307	DA 1.00000	\$ 2,434,307
168	REVENUE REQUIREMENT For All Company Facilities	(In 166 less In 167)			<u>\$ 37,325,852</u>

**MEMO: The Carrying Charge Calculations on lines 171 to 176 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 169 is included in the total on line 168.**

169	Not applicable on this template				
170	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				
171	Annual Rate	( (In 166 - In 270 - In 271) / In 213 x 100)			16.42%
172	Monthly Rate	(In 171 / 12)			1.37%
173	NET PLANT CARRYING CHARGE ON LINE 171 , w/o depreciation or ROE incentives (Note B)				
174	Annual Rate	( (In 166 - In 270 - In 271 - In 276) / In 213 x 100)			13.92%
175	NET PLANT CARRYING CHARGE ON LINE 174, w/o Return, income taxes or ROE incentives (Note B)				
176	Annual Rate	( (In 166 - In 270 - In 271 - In 276 - In 298 - In 299) / In 213 x 100)			3.84%
177	Not applicable on this template				
178	<b>REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES</b>				
179	Total Load Dispatch & Scheduling (Account 561)	Line 250 Below			2,102,150
180	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				1,089,485
181	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				205,436
182	Total 561 Internally Developed Costs	(Line 179 - Line 180 - Line 181)			<u>807,229</u>

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Line No.	(1) <u>RATE BASE CALCULATION</u>	(2) <u>Data Sources</u> <u>(See "General Notes")</u>	(3) <u>TO Total</u> <u>NOTE C</u>	(4) <u>Allocator</u>	(5) <u>Total</u> <u>Transmission</u>
183	GROSS PLANT IN SERVICE				
183	Production	(Worksheet A In 1.C)	540,095,917	NA	0.00000
184	Less: Production ARO (Enter Negative)	(Worksheet A In 2.C)	(3,337,422)	NA	0.00000
185	Transmission	(Worksheet A In 3.C & Ln 307)	438,744,866	DA	437,139,495
186	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 308)	-	TP	0.99634
187	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000
188	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000
189	Distribution	(Worksheet A In 5.C)	568,761,740	NA	0.00000
190	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.C)	-	NA	0.00000
191	General Plant	(Worksheet A In 7.C)	33,960,860	W/S	0.08595
192	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.C)	-	W/S	0.08595
193	Intangible Plant	(Worksheet A In 9.C)	16,666,518	W/S	0.08595
194	TOTAL GROSS PLANT	(sum Ins 183 to 193)	1,594,892,479	GP(h)=	0.276815
				GTD=	0.43388
195	ACCUMULATED DEPRECIATION AND AMORTIZATION				
196	Production	(Worksheet A In 12.C)	225,725,166	NA	0.00000
197	Less: Production ARO (Enter Negative)	(Worksheet A In 13.C)	(357,559)	NA	0.00000
198	Transmission	(Worksheet A In 14.C & 28.C)	141,779,874	TP1=	0.99589
199	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.C)	-	TP1=	0.99589
200	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000
201	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
202	Plus: Additional Transmission Depreciation for 2010 (In 276)		N/A	TP1	0.99589
203	Plus: Additional General & Intangible Depreciation for 2010 (In 275 + In 276)		N/A	W/S	0.08595
204	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
205	Distribution	(Worksheet A In 16.C)	139,979,041	NA	0.00000
206	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.C)	-	NA	0.00000
207	General Plant	(Worksheet A In 18.C)	7,194,870	W/S	0.08595
208	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.C)	-	W/S	0.08595
209	Intangible Plant	(Worksheet A In 20.C)	17,291,094	W/S	0.08595
210	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 196 to 209)	531,612,486		143,302,301
211	NET PLANT IN SERVICE				
212	Production	(In 183 + In 184 - In 196 - In 197)	311,390,888		-
213	Transmission	(In 185 + In 186 - In 198 - In 199)	296,964,992		295,941,682
214	Plus: Transmission Plant-in-Service Additions (In 187 - In 200)		N/A		N/A
215	Plus: Additional Trans Plant on Transferred Assets (In 188 - In 201)		N/A		N/A
216	Plus: Additional Transmission Depreciation for 2010 (-In 202)		N/A		N/A
217	Plus: Additional General & Intangible Depreciation for 2010 (-In 203)		N/A		N/A
218	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 204)		N/A		N/A
219	Distribution	(In 189 + In 190 - In 205 - In 206)	428,782,699		-
220	General Plant	(In 191 + In 192 - In 207 - In 208)	26,765,990		2,300,448
221	Intangible Plant	(In 193 - In 209)	(624,576)		(53,680)
222	TOTAL NET PLANT IN SERVICE	(sum Ins 212 to 221)	1,063,279,993	NP(h)=	0.280442
223	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
224	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.C)	(31,362,189)	NA	-
225	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.C)	(162,185,880)	DA	(46,357,239)
226	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.C)	(21,654,672)	DA	(1,380,134)
227	Account No. 190.1	(Worksheet B, In 17 & In 20.C)	14,157,012	DA	3,460,421
228	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.C)	-	DA	-
229	TOTAL ADJUSTMENTS	(sum Ins 224 to 228)	(201,045,729)		(44,276,952)
230	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.C & In 30.C)	7,436,551	DA	30,592
231	REGULATORY ASSETS	(Worksheet A In 36. (C))	-	DA	-
232	WORKING CAPITAL	(Note E)			
233	Cash Working Capital	(1/8 * In 253)	617,192		614,934
234	Transmission Materials & Supplies	(Worksheet C, In 2.(D))	103,391	TP	0.99634
235	A&G Materials & Supplies	(Worksheet C, In 3.(D))	119,885	W/S	0.08595
236	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.27682
237	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 6.G)	14,836,181	W/S	0.08595
238	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 6.F)	922,254	GP(h)	0.27682
239	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 6.E)	-	DA	1.00000
240	Prepayments (Account 165) - Unallocable	(Worksheet C, In 6.D)	(14,476,581)	NA	0.00000
241	TOTAL WORKING CAPITAL	(sum Ins 233 to 240)	2,122,322		2,258,665
242	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 7.B)	(236,193)	DA	1.00000
243	RATE BASE (sum Ins 222, 229, 230, 231, 241, 242)		871,556,944		255,964,562

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	(1)	(2)	(3)	(4)	(5)
Line	EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	Data Sources (See "General Notes")	TO Total	Allocator	Total Transmission
244	OPERATION & MAINTENANCE EXPENSE				
245	Production	321.80.b	457,856,290		
246	Distribution	322.156.b	29,693,612		
247	Customer Related Expense	322 & 323.164,171,178.b	8,740,355		
248	Regional Marketing Expenses	322.131.b	1,168,311		
249	Transmission	321.112.b	(821,880)		
250	TOTAL O&M EXPENSES	(sum Ins 244 to 248)	496,636,688		
251	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	2,102,150		
252	Less: Account 565	(Note H) 321.96.b	(7,861,567)		
253	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
253	Total O&M Allocable to Transmission	(Ins 248 - 250 - 251 - 252)	4,937,537	TP	0.99634
254	Administrative and General	323.197.b (Note J)	24,046,450		
255	Less: Acct. 924, Property Insurance	323.185.b	406,399		
256	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	4,099,565		
257	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(867,380)		
258	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	297,335		
259	Acct. 928, Reg. Com. Exp.	323.189.b	(496)		
260	Acct. 930.1, Gen. Advert. Exp.	323.191.b	398,905		
261	Acct. 930.2, Misc. Gen. Exp.	323.192.b	507,618		
262	Balance of A & G	(In 254 - sum In 255 to In 261)	19,204,504	W/S	0.08595
263	Plus: Acct. 924, Property Insurance	(In 255)	406,399	GP(h)	0.27682
264	Acct. 928 - Transmission Specific	#REF!	-	TP	0.99634
265	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 29.(E) (Note L)	-	TP	0.99634
266	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 35.(E) (Note L)	83,295	DA	1.00000
267	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,693,481	W/S	0.08595
268	A & G Subtotal	(sum Ins 262 to 267)	22,387,679		
269	O & M EXPENSE SUBTOTAL	(In 253 + In 268)	27,325,216		
270	Plus: TEA Settlement in Account 565	Company Records (Note H)	(8,835,297)	DA	1.00000
271	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA	1.00000
272	TOTAL O & M EXPENSE	(In 269 + In 270 + In 271)	18,489,919		
273	DEPRECIATION AND AMORTIZATION EXPENSE				
274	Production	336.2-6.f	20,344,274	NA	0.00000
275	Distribution	336.8.f	19,366,762	NA	0.00000
276	Transmission	336.7.f	7,420,678	TP1	0.99589
277	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
278	General	336.10.f	802,099	W/S	0.08595
279	Intangible	336.1.f	3,725,967	W/S	0.08595
280	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 274+275+276+277+278+279) (Note N)	51,659,780		
281	TAXES OTHER THAN INCOME				
282	Labor Related				
283	Payroll	Worksheet H In 21.(D)	1,655,606	W/S	0.08595
284	Plant Related				
285	Property	Worksheet H In 21.(C) & In 35.(C)	9,619,712	DA	3.618,147
286	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	(371,606)	NA	0.00000
287	Other	Worksheet H In 21.(E)	778,850	GP(h)	0.27682
288	TOTAL OTHER TAXES	(sum Ins 283 to 287)	11,682,562		
289	INCOME TAXES	(Note O)			
290	$T=1 - ((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p) =$		38.20%		
291	$EIT=(T/(1-T)) * (1-(WCLTD/WACC)) =$		36.04%		
292	where WCLTD=(In 327) and WACC = (In 330)				
293	and FIT, SIT & p are as given in Note O.				
294	$GRCF=1 / (1 - T) =$ (from In 290)		1.6182		
295	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(821,956)		
296	Income Tax Calculation	(In 291 * In 299)	27,249,727		
297	ITC adjustment	(In 294 * In 295)	(1,330,123)	NP(h)	0.28044
298	TOTAL INCOME TAXES	(sum Ins 296 to 297)	25,919,604		
299	RETURN ON RATE BASE (Rate Base*WACC)	(In 243 * In 330)	75,606,306		
300	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		8,298	DA	1.00000
301	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		
302	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 301 * In 291)		-		
303	TOTAL REVENUE REQUIREMENT	(sum Ins 272, 280, 288, 298, 299, 300, 301, 302)	183,366,469		

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SUPPORTING CALCULATIONS

In No.	TRANSMISSION PLANT INCLUDED IN PJM TARIFF								
304	Total transmission plant	(In 185)							438,744,866
305	Less transmission plant excluded from PJM Tariff (Note P)								
306	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)								1,605,371
307	Transmission plant included in PJM Tariff	(In 304 - In 305 - In 306)							437,139,495
308	Percent of transmission plant in PJM Tariff	(In 307 / In 304)						TP=	0.99634
309	WAGES & SALARY ALLOCATOR (W/S)	(Note R)							
310	Production	354.20.b	Direct Payroll	Payroll Billed from AEP Service Corp.	Total				
311	Transmission	354.21.b	9,541,025	2,878,391	12,419,416	NA	0.00000		-
312	Regional Market Expenses	354.22.b	1,320,732	1,123,582	2,444,314	TP	0.99634		2,435,370
313	Distribution	354.23.b	0	0	-	NA	0.00000		-
314	Other (Excludes A&G)	354.24,25,26.b	8,965,083	782,203	9,747,286	NA	0.00000		-
315	Total	(sum Ins 310 to 314)	21,655,359	6,680,465	28,335,824				2,435,370
316	Transmission related amount							W/S=	0.08595
317	WEIGHTED AVERAGE COST OF CAPITAL (WACC)								\$
318	Long Term Interest	(Worksheet L, In. 35, col. (D))							35,539,453
319	Preferred Dividends	(Worksheet L, In. 40, col. (D))							-
320	Development of Common Stock:								
321	Proprietary Capital	(FF1 p 112, Ln 16.c)							431,783,697
322	Less: Preferred Stock	(FF1 p 112, Ln 3.c)							-
323	Less: Account 216.1	(FF1 p 112, Ln 12 .c)							-
324	Less: Account 219	(FF1 p 112, Ln 15.c)							(600,942)
325	Common Stock	(In 321 - In 322 - In 323 - In 324)							432,384,639
326			\$	%			Cost (Note S)	Weighted	
327	Long Term Debt (Note T) Worksheet L, In 35, col. (B))		550,000,000	55.99%			0.0646		0.0362
328	Preferred Stock (In 322)		-	0.00%			-		0.0000
329	Common Stock (In 325)		432,384,639	44.01%			11.49%		0.0506
330	Total (Sum Ins 327 to 329)		982,384,639					WACC=	0.0867

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KENTUCKY POWER COMPANY

**Letter**

**Notes**

General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X

- A Revenue credits include:  
1) Forfeited Discounts.  
2) Miscellaneous Service Revenues.  
3) Rental revenues earned on assets included in the rate base.  
4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.  
5) Other electric revenues.  
6) Revenues for grandfathered PTP contracts included in the load divisor.  
See Worksheet E for details.
- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C **Transmission Plant balances in this study are projected as of December 31, 2009.**
- D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.  
**The company will not include the ADIT portion of deferred hedge gains and losses in rate base.**
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 253. It excludes:  
1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancillary Services Revenue, as shown on line 250.  
2) AEP transmission equalization transfers, as shown on line 251  
3) The impact of state regulatory deferrals and amortizations, as shown on line 252  
4) All A&G Expenses, as shown on line 268.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 242 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 300.
- G **Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 180 & 181 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.**
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 253. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 270 and 271 to determine the total O&M collected in the formula. The amounts on lines 270 and 271 are also excluded in the calculation of the FCR percentage calculated on lines 170 through 176.  
The addbacks on lines 270 and 271 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.  
**The company records referenced on lines 270 and 271 is the KENTUCKY POWER COMPANY general ledger.**
- I Removes the impact of state regulatory deferrals or their amortization from O&M expense.
- J **General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.**
- K These deductions on lines 256 through 258 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- L Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Acct 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M **See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the seven operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.**
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and p = the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.  
A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)  
(In 295) multiplied by  $(1/(1-T))$ . If the applicable tax rates are zero enter 0.  
Inputs Required: FIT = 35.00%  
SIT= 4.93% (State Income Tax Rate or Composite SIT. Worksheet G)  
p = 0.00% (percent of federal income tax deductible for state purposes)
- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (In 318) / long term debt (In 327). Preferred Stock cost rate = preferred dividends (In 319) / preferred outstanding (In 328). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for remaining a member of the PJM RTO.  
**In the Projected & Historic templates, the interest expense on long-term debt is the sum of a full year's interest expense at the coupon rate for each issuance outstanding as of December 31 of the historic year. The projected expense for variable rate debt will be based on the effective rate at December 31. These conventions ensure that the expense used in the projection will reflect a full year, similar to the actual expense that will appear in the subsequent true-up of the projection, and minimize the impact on the true-up of using a partial year interest expense. The projection will reflect the actual historic-year expense recorded for issuance expenses, discounts and premiums, and gains or losses on reacquired debt. Eligible hedging gains or losses will be limited to five basis points of the projected capital structure. Details and calculations are shown on Worksheet L.**
- T This note only applies to Indiana Michigan Power Company.
- U **This note only applies to the true-up template.**

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Line No.			Total	Allocator	Transmission Amount
1	REVENUE REQUIREMENT (w/o incentives)	(In 138)			\$40,476,610
2	REVENUE CREDITS	(Note A) (Worksheet E)	2,434,307	DA 1.00000	\$ 2,434,307
3	REVENUE REQUIREMENT For All Company Facilities	(In 1 less In 2)			<u>\$ 38,042,303</u>

**MEMO: The Carrying Charge Calculations on lines 6 to 11 below are used in calculating project revenue requirements billed through PJM Schedule 12, Transmission Enhancement Charges. The total non-incentive revenue requirements for these projects shown on line 4 is included in the total on line 3.**

4	Revenue Requirement for PJM Schedule 12 Facilities (w/o incentives) (Worksheet K)		-	DA 1.00000	\$ -
5	NET PLANT CARRYING CHARGE w/o intra-AEP charges or credits or ROE incentives (Note B)				
6	Annual Rate	( (In 1 - In 105 - In 106) / In 48 x 100)			16.68%
7	Monthly Rate	(In 6 / 12)			1.39%
8	NET PLANT CARRYING CHARGE ON LINE 6 , w/o depreciation or ROE incentives (Note B)				
9	Annual Rate	( (In 1 - In 105 - In 106 - In 111) / In 48 x 100)			14.18%
10	NET PLANT CARRYING CHARGE ON LINE 9, w/o Return, income taxes or ROE incentives (Note B)				
11	Annual Rate	( (In 1 - In 105 - In 106 - In 111 - In 133 - In 134) / In 48 x 100)			3.85%
12	ADDITIONAL REVENUE REQUIREMENT for projects w/ incentive ROE's (Note B) (Worksheet K)				-
13	<b>REVENUE REQUIREMENT FOR SCHEDULE 1A CHARGES</b>				
14	Total Load Dispatch & Scheduling (Account 561)	Line 85 Below			2,102,150
15	Less: Load Dispatch - Scheduling, System Control and Dispatch Services (321.88.b)				1,089,485
16	Less: Load Dispatch - Reliability, Planning & Standards Development Services (321.92.b)				205,436
17	Total 561 Internally Developed Costs	(Line 14 - Line 15 - Line 16)			<u>807,229</u>

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Line No.	(1)	(2)	(3)	(4)	(5)
	<u>RATE BASE CALCULATION</u>	<u>Data Sources</u> <u>(See "General Notes")</u>	<u>TO Total</u> <u>NOTE C</u>	<u>Allocator</u>	<u>Total</u> <u>Transmission</u>
18	GROSS PLANT IN SERVICE				
18	Production	(Worksheet A In 1.E)	533,657,491	NA	0.00000
19	Less: Production ARO (Enter Negative)	(Worksheet A In 2.E)	(3,337,422)	NA	0.00000
20	Transmission	(Worksheet A In 3.C & Ln 142)	435,274,642	DA	433,672,214
21	Less: Transmission ARO (Enter Negative)	(Worksheet A In 4.C & Ln 143)	-	TP	0.99632
22	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	NA	0.00000
23	Plus: Additional Trans Plant on Transferred Assets (Worksheet I)		N/A	NA	0.00000
24	Distribution	(Worksheet A In 5.E)	548,736,390	NA	0.00000
25	Less: Distribution ARO (Enter Negative)	(Worksheet A In 6.E)	-	NA	0.00000
26	General Plant	(Worksheet A In 7.E)	33,810,252	W/S	0.08594
27	Less: General Plant ARO (Enter Negative)	(Worksheet A In 8.E)	-	W/S	0.08594
28	Intangible Plant	(Worksheet A In 9.E)	19,513,292	W/S	0.08594
29	TOTAL GROSS PLANT	(sum Ins 18 to 28)	1,567,654,644	<b>GP(h)=</b> <b>GTD=</b>	<b>0.27956</b> <b>0.00000</b>
30	ACCUMULATED DEPRECIATION AND AMORTIZATION				
31	Production	(Worksheet A In 12.E)	217,947,143	NA	0.00000
32	Less: Production ARO (Enter Negative)	(Worksheet A In 13.E)	(278,323)	NA	0.00000
33	Transmission	(Worksheet A In 14.E & 28.E)	138,621,404	TP1=	0.99589
34	Less: Transmission ARO (Enter Negative)	(Worksheet A In 15.E)	-	TP1=	0.99589
35	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A	DA	1.00000
36	Plus: Additional Projected Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
37	Plus: Additional Transmission Depreciation for 2010 (In 111)		N/A	TP1	0.99589
38	Plus: Additional General & Intangible Depreciation for 2010 (In 110 + In 111)		N/A	W/S	0.08594
39	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I)		N/A	DA	1.00000
40	Distribution	(Worksheet A In 16.E)	136,808,237	NA	0.00000
41	Less: Distribution ARO (Enter Negative)	(Worksheet A In 17.E)	-	NA	0.00000
42	General Plant	(Worksheet A In 18.E)	6,881,930	W/S	0.08594
43	Less: General Plant ARO (Enter Negative)	(Worksheet A In 19.E)	-	W/S	0.08594
44	Intangible Plant	(Worksheet A In 20.E)	18,782,310	W/S	0.08594
45	TOTAL ACCUMULATED DEPRECIATION	(sum Ins 31 to 44)	518,762,700		1,614,241
46	NET PLANT IN SERVICE				
47	Production	(In 18 + In 19 - In 31 - In 32)	312,651,249		-
48	Transmission	(In 20 + In 21 - In 33 - In 34)	296,653,238		295,620,104
49	Plus: Transmission Plant-in-Service Additions (In 22 - In 35)		N/A		N/A
50	Plus: Additional Trans Plant on Transferred Assets (In 23 - In 36)		N/A		N/A
51	Plus: Additional Transmission Depreciation for 2010 (-In 37)		N/A		N/A
52	Plus: Additional General & Intangible Depreciation for 2010 (-In 38)		N/A		N/A
53	Plus: Additional Accum Deprec on Transferred Assets (Worksheet I) (-In 39)		N/A		N/A
54	Distribution	(In 24 + In 25 - In 40 - In 41)	411,928,153		-
55	General Plant	(In 26 + In 27 - In 42 - In 43)	26,928,323		2,314,348
56	Intangible Plant	(In 28 - In 44)	730,983		62,824
57	TOTAL NET PLANT IN SERVICE	(sum Ins 47 to 56)	1,048,891,944	<b>NP(h)=</b>	<b>0.28411</b>
58	DEFERRED TAX ADJUSTMENTS TO RATE BASE	(Note D)			
59	Account No. 281.1 (enter negative)	(Worksheet B, In 2 & In 5.E)	(32,077,284)	NA	-
60	Account No. 282.1 (enter negative)	(Worksheet B, In 7 & In 10.E)	(146,867,240)	DA	(44,405,389)
61	Account No. 283.1 (enter negative)	(Worksheet B, In 12 & In 15.E)	(24,718,173)	DA	(1,500,923)
62	Account No. 190.1	(Worksheet B, In 17 & In 20.E)	28,437,137	DA	3,550,131
63	Account No. 255 (enter negative)	(Worksheet B, In 24 & In 25.E)	-	DA	-
64	TOTAL ADJUSTMENTS	(sum Ins 59 to 63)	(175,225,560)		(42,356,181)
65	PLANT HELD FOR FUTURE USE	(Worksheet A In 29.E & In 30.E)	7,122,749	DA	30,592
66	REGULATORY ASSETS	(Worksheet A In 36. (E))	-	DA	-
67	WORKING CAPITAL	(Note E)			
68	Cash Working Capital	(1/8 * In 88)	617,192		614,920
69	Transmission Materials & Supplies	(Worksheet C, In 2.F)	70,704	TP	0.99632
70	A&G Materials & Supplies	(Worksheet C, In 3.F)	107,407	W/S	0.08594
71	Stores Expense	(Worksheet C, In 4.(D))	-	GP(h)	0.27956
72	Prepayments (Account 165) - Labor Allocated	(Worksheet C, In 8.G)	15,943,889	W/S	0.08594
73	Prepayments (Account 165) - Gross Plant	(Worksheet C, In 8.F)	850,575	GP(h)	0.27956
74	Prepayments (Account 165) - Transmission Only	(Worksheet C, In 8.E)	-	DA	1.00000
75	Prepayments (Account 165) - Unallocable	(Worksheet C, In 8.D)	(15,518,180)	NA	0.00000
76	TOTAL WORKING CAPITAL	(sum Ins 68 to 75)	2,071,586		2,302,675
77	IPP CONTRIBUTIONS FOR CONSTRUCTION	(Note F) (Worksheet D, In 8 (B))	(232,207)	DA	1.00000
78	RATE BASE (sum Ins 57, 64, 65, 66, 76, 77)		882,628,512		257,742,156

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KENTUCKY POWER COMPANY

Line No.	(1) EXPENSE, TAXES, RETURN & REVENUE REQUIREMENTS CALCULATION	(2) Data Sources (See "General Notes")	(3) TO Total	(4) Allocator	(5) Total Transmission
79	OPERATION & MAINTENANCE EXPENSE				
80	Production	321.80.b	457,856,290		
81	Distribution	322.156.b	29,693,612		
82	Customer Related Expense	322.164,171,178.b	8,740,355		
83	Regional Marketing Expenses	322.131.b	1,168,311		
84	Transmission	321.112.b	(821,880)		
85	TOTAL O&M EXPENSES	(sum Ins 79 to 83)	496,636,688		
86	Less: Total Account 561	(Note G) (Worksheet F, In 14.C)	2,102,150		
87	Less: Account 565	(Note H) 321.96.b	(7,861,567)		
88	Less: Regulatory Deferrals & Amortizations	(Note I) (Worksheet F, In 4.C)	-		
	Total O&M Allocable to Transmission	(Ins 83 - 85 - 86 - 87)	4,937,537	TP 0.99632	4,919,360
89	Administrative and General	323.197.b (Note J)	24,046,450		
90	Less: Acct. 924, Property Insurance	323.185.b	406,399		
91	Acct. 9260039 PBOP Expense	PBOP Worksheet O Line 9 & 10, (Note K)	4,099,565		
92	Acct. 9260057 PBOP Medicare Subsidy	PBOP Worksheet O Line 11, (Note K)	(867,380)		
93	PBOP Expense Billed From AEPSC	PBOP Worksheet O Line 13, (Note K)	297,335		
94	Acct. 928, Reg. Com. Exp.	323.189.b	(496)		
95	Acct. 930.1, Gen. Advert. Exp.	323.191.b	398,905		
96	Acct. 930.2, Misc. Gen. Exp.	323.192.b	507,618		
97	Balance of A & G	(In 89 - sum in 90 to in 96)	19,204,504	W/S 0.08594	1,650,526
98	Plus: Acct. 924, Property Insurance	(In 90)	406,399	GP(h) 0.27956	113,613
99	Acct. 928 - Transmission Specific	#REF!	-	TP 0.99634	-
100	Acct 930.1 - Only safety related ads -Direct	Worksheet F In 29.(E) (Note L)	-	TP 0.99634	-
101	Acct 930.2 - Misc Gen. Exp. - Trans	Worksheet F In 35.(E) (Note L)	83,295	DA 1.00000	83,295
102	Settlement Approved PBOP Recovery	PBOP Worksheet O, Col. C, Line 4, (Note M)	2,693,481	W/S 0.08594	231,491
103	A & G Subtotal	(sum Ins 97 to 102)	22,387,679		2,078,925
104	O & M EXPENSE SUBTOTAL	(In 88 + In 103)	27,325,216		6,998,285
105	Plus: TEA Settlement in Account 565	Company Records (Note H)	(8,835,297)	DA 1.00000	(8,835,297)
106	Plus: Transmission Lease Payments To Affiliates in Acct 565 (Company Records) (Note H)		-	DA 1.00000	-
107	TOTAL O & M EXPENSE	(In 104 + In 105 + In 106)	18,489,919		(1,837,012)
108	DEPRECIATION AND AMORTIZATION EXPENSE				
109	Production	336.2-6.f	20,344,274	NA 0.00000	-
110	Distribution	336.8.f	19,366,762	NA 0.00000	-
111	Transmission	336.7.f	7,420,678	TP1 0.99589	7,390,203
112	Plus: Transmission Plant-in-Service Additions (Worksheet I)		N/A		N/A
113	General	336.10.f	802,099	W/S 0.08594	68,936
114	Intangible	336.1.f	3,725,967	W/S 0.08594	320,227
115	TOTAL DEPRECIATION AND AMORTIZATION	(Ln 109+110+111+112+113+114)	51,659,780		7,779,366
116	TAXES OTHER THAN INCOME	(Note N)			
117	Labor Related				
118	Payroll	Worksheet H In 21.(D)	1,655,606	W/S 0.08594	142,291
119	Plant Related				
120	Property	Worksheet H In 21.(C) & In 35.(C)	9,619,712	DA	3,618,147
121	Gross Receipts/Sales & Use	Worksheet H In 21.(F)	(371,606)	NA 0.00000	-
122	Other	Worksheet H In 21.(E)	778,850	GP(h) 0.27956	217,736
123	TOTAL OTHER TAXES	(sum Ins 118 to 122)	11,682,562		3,978,173
124	INCOME TAXES	(Note O)			
125	$T=1 - (((1 - SIT) * (1 - FIT)) / (1 - SIT * FIT * p)) =$		38.20%		
126	$EIT=(T/(1-T)) * (1-(WCLD/WACC)) =$		37.56%		
127	where WCLD=(In 162) and WACC = (In 165)				
128	and FIT, SIT & p are as given in Note O.				
129	$GRCF=1 / (1 - T) =$ (from In 125)		1.6182		
130	Amortized Investment Tax Credit (enter negative)	(FF1 p.114, In 19.c)	(821,956)		
131	Income Tax Calculation	(In 126 * In 134)	28,917,138		8,444,284
132	ITC adjustment	(In 129 * In 130)	(1,330,123)	NP(h) 0.28411	(377,897)
133	TOTAL INCOME TAXES	(sum Ins 131 to 132)	27,587,016		8,066,387
134	RETURN ON RATE BASE (Rate Base*WACC)	(In 78 * In 165)	76,986,718		22,481,398
135	INTEREST ON IPP CONTRIBUTION FOR CONST. (Note F) (Worksheet D, In 2.(B))		8,298	DA 1.00000	8,298
136	(Gains) / Losses on Sales of Plant Held for Future Use (Worksheet N, In 4, Cols. ((F) & (H))		-		-
137	Tax Impact on Net Loss / (Gain) on Sales of Plant Held for Future Use (In 136 * In126)		-		-
138	TOTAL REVENUE REQUIREMENT		186,414,293		40,476,610
	(sum Ins 107, 115, 123, 133, 134, 135)				

AEP East Companies  
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KENTUCKY POWER COMPANY

SUPPORTING CALCULATIONS

In								
<u>No.</u>	TRANSMISSION PLANT INCLUDED IN PJM TARIFF							
139	Total transmission plant	(In 20)					435,274,642	
140	Less transmission plant excluded from PJM Tariff (Note P)						-	
141	Less transmission plant included in OATT Ancillary Services (Worksheet A, In 23, Col. (C)) (Note Q)						1,602,428	
142	Transmission plant included in PJM Tariff	(In 139 - In 140 - In 141)					433,672,214	
143	Percent of transmission plant in PJM Tariff	(In 142 / In 139)				<b>TP=</b>	<b>0.99632</b>	
144	WAGES & SALARY ALLOCATOR (W/S)	(Note R)	Direct Payroll	Payroll Billed from AEP Service Corp.	Total			
145	Production	354.20.b	9,541,025	2,878,391	12,419,416	NA	0.00000 -	
146	Transmission	354.21.b	1,320,732	1,123,582	2,444,314	TP	0.99632 2,435,315	
147	Regional Market Expenses	354.22.b	0	0	-	NA	0.00000 -	
148	Distribution	354.23.b	8,965,083	782,203	9,747,286	NA	0.00000 -	
149	Other (Excludes A&G)	354.24,25,26.b	1,828,519	1,896,289	3,724,808	NA	0.00000 -	
150	Total	(sum Ins 145 to 149)	21,655,359	6,680,465	28,335,824		2,435,315	
151	Transmission related amount					<b>W/S=</b>	<b>0.08594</b>	
152	WEIGHTED AVERAGE COST OF CAPITAL (WACC)						\$	
153	Long Term Interest	(Worksheet M, In. 21, col. (E))					30,813,817	
154	Preferred Dividends	(Worksheet M, In. 56, col. (E))					-	
155	<u>Development of Common Stock:</u>						Average	
156	Proprietary Capital	(Worksheet M, In. 1, col. (E))					414,896,185	
157	Less: Preferred Stock	(Worksheet M, In. 2, col. (E))					-	
158	Less: Account 216.1	(Worksheet M, In. 3, col. (E))					-	
159	Less: Account 219	(Worksheet M, In. 4, col. (E))					(270,679)	
160	Common Stock	(In 156 - In 157 - In 158 - In 159)					415,166,864	
161		Average \$		<b>Capital Structure Weighting</b>		Cost		
162	Long Term Debt (Note T) W/S M, In 11, In 22, col. (E))	485,000,000		Actual	Cap Limit	(Note S)	Weighted	
163	Preferred Stock (In 157)	-		53.88%	0.00%	0.0635	0.0342	
164	Common Stock (In 160)	415,166,864		0.00%	0.00%	-	0.0000	
165	Total (Sum Ins 162 to 164)	900,166,864		46.12%	0.00%	11.49%	0.0530	
						<b>WACC=</b>	<b>0.0872</b>	
166	Capital Structure Equity Limit (Note U)	50.0%						

AEP East Companies  
 Transmission Cost of Service Formula Rate  
 Utilizing Actual Cost Data for 2009 with Average Ratebase Balances

KENTUCKY POWER COMPANY

**Letter**

**Notes**

General Notes: a) References to data from Worksheets are indicated as: Worksheet X, Line#.Column.X

- A Revenue credits include:  
 1) Forfeited Discounts.  
 2) Miscellaneous Service Revenues.  
 3) Rental revenues earned on assets included in the rate base.  
 4) Revenues for associated business projects provided by employees whose labor and overhead costs are in the transmission cost of service.  
 5) Other electric revenues.  
 6) Revenues for grandfathered PTP contracts included in the load divisor.  
 See Worksheet E for details.
- B The annual and monthly net plant carrying charges on page 1 are used to compute the revenue requirement for RTEP sponsored upgrades or those projects receiving approved incentive-ROE's.
- C **Transmission Plant balances in this study reflect the average of the balances at December 31, 2008 and December 31, 2009.**
- D The total-company balances shown for Accounts 281, 282, 283, 190 only reflect ADIT that relates to utility operations. The balance of Account 255 is reduced by prior flow throughs and is completely excluded if the utility chose to utilize amortization of tax credits against FIT expense. An exception to this is pre-1971 ITC balances, which are required to be taken as an offset to rate base. Account 281 is not allocated. In compliance with FERC Rulemaking RM02-7-000, Asset Retirement Obligation deferrals have been removed from ratebase. Transmission ADIT allocations are shown on WS B.  
**The company will not include the ADIT portion of deferred hedge gains and losses in rate base.**
- E Cash Working Capital assigned to transmission is one-eighth of O&M allocated to transmission, as shown on line 88. It excludes:  
 1) Load Scheduling & Dispatch Charges in account 561 that are collected in the OATT Ancillary Services Revenue, as shown on line 85.  
 2) AEP transmission equalization transfers, as shown on line 86  
 3) The impact of state regulatory deferrals and amortizations, as shown on line 87  
 4) All A&G Expenses, as shown on line 103.
- F Consistent with Paragraph 657 of Order 2003-A, the amount on line 77 is equal to the balance of IPP System Upgrade Credits owed to transmission customers that made contributions toward the construction of System upgrades, and includes accrued interest and unreturned balance of contributions. The annual interest expense is included on line 135.
- G **Removes from the cost of service the Load Scheduling and Dispatch expenses booked to accounts 561.1 through 561.8. Expenses recorded in these accounts, with the exception of 561.4 & 561.8 (lines 15 & 16 above) are recovered in Schedule 1A, OATT ancillary services rates. See Worksheet F, lines 5 through 14, for descriptions and the Form 1 Source of these accounts' balances.**
- H Removes cost of transmission service provided by others to determine the basis of cash working capital on line 88. To the extent such service is incurred to provide the PJM service at issue, e.g. transmission equalization agreement, such costs are added back on lines 105 and 106 to determine the total O&M collected in the formula. The amounts on lines 105 and 106 are also excluded in the calculation of the FCR percentage calculated on lines 5 through 11.  
 The addbacks on lines 105 and 106 of activity recorded in 565 represents inter-company sales or purchases of transmission capacity necessary to meet each AEP company's transmission load relative to their available transmission capacity.  
**The company records referenced on lines 105 and 106 is the KENTUCKY POWER COMPANY general ledger.**
- I Removes the impact of state regulatory deferrals or their amortization from O&M expense. applicable only for state regulatory purposes.
- J **General Plant and Administrative & General expenses, other than in accounts 924, 928, and 930, will be functionalized based on the Wages & Salaries "W/S" allocator. The allocation basis for accounts 924, 928 and 930 are separately presented in the formula. A change in the allocation method for an account must be approved via a 205 filing with the FERC.**
- K These deductions on lines 91 through 93 are to remove from the cost of service the expenses recorded by the company for Postemployment Benefits Other than Pensions (PBOP). See Note M below for the recoverable PBOP expense.
- L Expenses reported for these A&G accounts will be included in the cost of service only to the extent they are directly assignable to transmission service. Worksheet F allocates these expense items. Act 928 Includes Regulatory Commission expenses itemized in FERC Form-1 at page 351, column H. FERC Assessment Fees and Annual Charges shall not be allocated to transmission. Only safety-related and educational advertising costs in Account 930.1 are included in the TCOS. Account 930.2 includes the expenses incurred by the transmission function for Associated Business Development revenues given as a credit to the TCOS on Worksheet E.
- M **See note K above. Per the settlement in Docket ER08-1329, recoverable PBOP expense is based on an annual total for the seven operating companies that is ratioed to them based on the total of actual annual PBOP costs, including charges from the AEP Service Corporation. The calculation of the recoverable amount for each company is shown on Worksheet O, and the process for updating the annual total is documented on Attachment F, Allowable PBOP Expense Formula.**
- N Includes only FICA, unemployment, highway, property and other assessments charged in the current year. Gross receipts, sales & use and taxes related to income are excluded.
- O The currently effective income tax rate, where FIT is the Federal income tax rate; SIT is the State income tax rate, and  $p =$  the percentage of federal income tax deductible for state income taxes. See Worksheet G for the development of the Company's composite SIT.  
 A utility that elected to utilize amortization of tax credits against taxable income, rather than book tax credits to Account No. 255 and reduce rate base, must reduce its income tax expense by the amount of the Amortized Investment Tax Credit (Form 1, 266.8.f)  
 (In 130) multiplied by  $(1/1-T)$ . If the applicable tax rates are zero enter 0.  
 Inputs Required: FIT = 35.00%  
 SIT = 4.93% (State Income Tax Rate or Composite SIT. Worksheet G)  
 $p =$  0.00% (percent of federal income tax deductible for state purposes)
- P Removes plant excluded from the OATT because it does not meet the PJM's definition of Transmission Facilities or is otherwise ineligible to be recovered under the OATT.
- Q Removes transmission plant (e.g. step-up transformers) included in the development of OATT ancillary service rates and not already removed for reasons indicated in Note P.
- R Includes functional wages & salaries billed by AEP Service Corporation for support of the operating company.
- S Long Term Debt cost rate = long-term interest (In 153) / long term debt (In 162). Preferred Stock cost rate = preferred dividends (In 154) / preferred outstanding (In 163). Common Stock cost rate (ROE) = 11.49%, the rate accepted by FERC in Docket No. ER08-1329. It includes an additional 50 basis points for PJM RTO membership.  
**Interest expense for the true-up WACC is based on actual expenses for the true-up year. The amount of eligible hedging gains or losses included in total interest expense is limited to five basis points of the true-up capital structure. Details and calculations of the true-up weighted average cost of capital are shown on Worksheet M. Eligible Hedging Gains and Losses are defined in the Formula Protocols in the tariff, and on Worksheet M.**
- T This note only applies to Indiana Michigan Power Company.
- U **Per Settlement, equity for KENTUCKY POWER COMPANY is limited to 50% of Capital Structure. If the percentage of equity exceeds the cap, the excess is included in weighted percentage of long term debt in the capital structure. During the period ended December 31, 2011 the equity cap is in effect. During this period, a change in the cap percentage must be approved via a 205 filing with the FERC.**

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet A Supporting Plant Balances  
KENTUCKY POWER COMPANY

<u>Line</u>	<u>(A)</u>	<u>(B)</u>	<u>(C)</u>	<u>(D)</u>	<u>(E)</u>
<u>Number</u>	<u>Rate Base Item &amp; Supporting Balance</u>	<u>Source of Data</u>	<u>Balance @ December 31, 2009</u>	<u>Balance @ December 31, 2008</u>	<u>Average Balance for 2009</u>
<b>NOTE: Functional ARO investment and accumulated depreciation balances shown below are included in the total functional balances shown here.</b>					
<b>Plant Investment Balances</b>					
1	Production Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 46	540,095,917	527,219,064	533,657,491
2	Production Asset Retirement Obligation (ARO)	FF1, page 205&204, Col.(g)&(b), lns 15,24,34,44	3,337,422	3,337,422	3,337,422
3	Transmission Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 58	438,744,866	431,804,417	435,274,642
4	Transmission Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 57	-	-	-
5	Distribution Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 75	568,761,740	528,711,039	548,736,390
6	Distribution Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 74	-	-	-
7	General Plant In Service	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 99	33,960,860	33,659,644	33,810,252
8	General Asset Retirement Obligation	FF1, page 207 Col.(g) & pg. 206 Col. (b), ln 98	-	-	-
9	Intangible Plant In Service	FF1, page 205 Col.(g) & pg. 204 Col. (b), ln 5	16,666,518	22,360,066	19,513,292
10	Total Property Investment Balance	(Sum of Lines: 3, 1, 5, 7, 9)	1,598,229,901	1,543,754,230	1,570,992,066
11	Total ARO Balance (included in total on line 10)	(Sum of Lines: 4, 2, 6, 8)	3,337,422	3,337,422	3,337,422
<b>Accumulated Depreciation &amp; Amortization Balances</b>					
12	Production Accumulated Depreciation	FF1, page 219, lns 20-24, Col. (b)	225,725,166	210,169,120	217,947,143
13	Production ARO Accumulated Depreciation	Company Records - Note 1	357,559	199,087	278,323
14	Transmission Accumulated Depreciation	FF1, page 219, ln 25, Col. (b)	141,779,874	135,462,933	138,621,404
15	Transmission ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
16	Distribution Accumulated Depreciation	FF1, page 219, ln 26, Col. (b)	139,979,041	133,637,433	136,808,237
17	Distribution ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
18	General Accumulated Depreciation	FF1, page 219, ln 28, Col. (b)	7,194,870	6,568,989	6,881,930
19	General ARO Accumulated Depreciation	Company Records - Note 1	-	-	-
20	Intangible Accumulated Amortization	FF1, page 200, ln 21, Col. (b)	17,291,094	20,273,525	18,782,310
21	Total Accumulated Depreciation or Amortization	(Sum of Lines: 14, 12, 16, 18, 20)	531,970,045	506,112,000	519,041,023
22	Total ARO Balance (included in total on line 21)	(Sum of Lines: 15, 13, 17, 19)	357,559	199,087	278,323
<b>Generation Step-Up Units</b>					
23	GSU Investment Amount	Company Records - Note 1	1,605,371	1,599,484	1,602,428
24	GSU Accumulated Depreciation	Company Records - Note 1	582,061	556,525	569,293
25	GSU Net Balance	(Line 23 - Line 24)	1,023,310	1,042,959	1,033,135
<b>Transmission Accumulated Depreciation Net of GSU Accumulated Depreciation</b>					
26	Transmission Accumulated Depreciation	(Line 14 Above)	141,779,874	135,462,933	138,621,404
27	Less: GSU Accumulated Depreciation	(Line 24 Above)	582,061	556,525	569,293
28	Subtotal of Transmission Net of GSU	(Line 26 - Line 27)	141,197,813	134,906,408	138,052,111
<b>Plant Held For Future Use</b>					
29	Plant Held For Future Use	FF1, page 214, ln 47, Col. (d)	7,436,551	6,808,947	7,122,749
30	Transmission Plant Held For Future	Company Records - Note 1	30,592	30,592	30,592
<b>Regulatory Assets and Liabilities Approved for Recovery In Ratebase</b>					
Note: Regulatory Assets & Liabilities can only be included in ratebase pursuant to a 205 filing with the FERC.					
31					-
32					-
33					-
34					-
35					-
36	Total Regulatory Deferrals Included in Ratebase		-	-	-

NOTE 1 On this worksheet, "Company Records" refers to AEP's property accounting ledger.

NOTE: The ratebase should not include the unamortized balance of hedging gains or losses.

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet B Supporting ADIT and ITC Balances  
KENTUCKY POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) Source</u>	<u>(C) Balance @ December 31, 2009</u>	<u>(D) Balance @ December 31, 2008</u>	<u>(E) Average Balance for 2009</u>
1	<b><u>Account 281</u></b>				
2	Year End Utility Deferrals	FF1, p. 272 - 273, ln 8, Col. (k)	31,362,189	32,792,379	32,077,284
3	Less: ARO Related Deferrals	Company Records - Note 1	-	-	-
4	Less: Other Excluded Deferrals	Company Records - Note 1	31,362,189	32,792,379	32,077,284
5	Transmission Related Deferrals	Ln 2 - ln 3 - ln 4	-	-	-
6	<b><u>Account 282</u></b>				
7	Year End Utility Deferrals	FF1, p. 274 - 275, ln 5, Col. (k)	162,185,880	131,548,600	146,867,240
8	Less: ARO Related Deferrals	Company Records - Note 1	490,807	468,472	479,640
9	Less: Other Excluded Deferrals	Company Records - Note 1	115,337,834	88,626,589	101,982,212
10	Transmission Related Deferrals	Ln 7 - ln 8 - ln 9	46,357,239	42,453,539	44,405,389
11	<b><u>Account 283</u></b>				
12	Year End Utility Deferrals	FF1, p. 276 - 277, ln 9, Col. (k)	21,654,672	27,781,673	24,718,173
13	Less: ARO Related Deferrals	Company Records - Note 1	-	0	-
14	Less: Other Excluded Deferrals	Company Records - Note 1	20,274,538	26,159,962	23,217,250
15	Transmission Related Deferrals	Ln 12 - ln 13 - ln 14	1,380,134	1,621,711	1,500,923
16	<b><u>Account 190</u></b>				
17	Year End Utility Deferrals	FF1, p. 234, ln 8, Col. (c)	14,157,012	42,717,261	28,437,137
18	Less: ARO Related Deferrals	Company Records - Note 1	1,232,754	1,146,114	1,189,434
19	Less: Other Excluded Deferrals	Company Records - Note 1	9,463,837	37,931,306	23,697,572
20	Transmission Related Deferrals	Ln 17 - ln 18 - ln 19	3,460,421	3,639,841	3,550,131
21	<b><u>Account 255</u></b>				
22	Year End ITC Balances	FF1, p. 266-267, ln 8, Col. (h)	1,697,364	2,519,320	2,108,342
23	Less: Balances Not Qualified for Ratebase	Company Records - Note 1	1,697,364	2,519,320	2,108,342
24	ITC Balances Includeable Ratebase	Ln 22 - ln 23	-	-	-
25	Transmission Related Deferrals	Company Records - Note 1	0	0	-

NOTE 1 On this worksheet, "Company Records" refers to AEP's tax accounting ledger.

NOTE 2 ADIT balances should exclude balances related to hedging activity.

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet C Supporting Working Capital Rate Base Adjustments  
KENTUCKY POWER COMPANY

(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
<b>Materials &amp; Supplies</b>								
Line Number	Source	Balance @ December 31, 2009	Balance @ December 31, 2008	Average Balance for 2009				
1								
2	Transmission Materials & Supplies	FF1, p. 227, ln 8, Col. (c) & (b)	103,391	38,016	70,704			
3	General Materials & Supplies	FF1, p. 227, ln 11, Col. (c) & (b)	119,885	94,928	107,407			
4	Stores Expense (Undistributed)	FF1, p. 227, ln 16, Col. (c) & (b)	0	0	-			

**Prepayment Balance Summary**

	Average of YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	
5							
6	Totals as of December 31, 2009	1,281,855	(14,476,581)	0	922,254	14,836,181	15,758,435
7	Totals as of December 31, 2008	1,270,714	(16,559,778)		778,895	17,051,597	17,830,492
8	<b>Average Balance</b>	<b>1,276,285</b>	<b>(15,518,180)</b>	<b>-</b>	<b>850,575</b>	<b>15,943,889</b>	<b>16,794,464</b>

**Prepayments Account 165 - Balance @ 12/31/2009**

9	Acc. No.	Description	2009 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
10	1650001	Prepaid Insurance	367,942	-	-	367,942	-	367,942	Plant Related Insurance Policies
11	165000209	Prepaid Taxes	374,877	-	-	374,877	-	374,877	Prepaid PSC Fees
12	1650009	Prepaid Carry Cost-Factored AR	19,411	19,411	-	-	-	-	AR Factoring - Retail Only
13	1650010	Prepaid Pension Benefits	14,836,181	-	-	-	14,836,181	14,836,181	Prefunded Pension Expense
14	1650014	FAS 158 Qual Contra Asset	(14,836,181)	(14,836,181)	-	-	-	-	SFAS 158 Offset
15	1650016	FAS 112 ASSETS	0	-	-	-	-	-	SFAS 112 Overfunding Asset
16	165001209	Prepaid Sales/Use Taxes	340,189	340,189	-	-	-	-	
17	1650021	Prepaid Insurance - EIS	179,435	-	-	179,435	-	179,435	
<b>Subtotal - Form 1, p 111.57.c</b>			<b>1,281,855</b>	<b>(14,476,581)</b>	<b>0</b>	<b>922,254</b>	<b>14,836,181</b>	<b>15,758,435</b>	

**Prepayments Account 165 - Balance @ 12/31/2008**

18	Acc. No.	Description	2008 YE Balance	Excludable Balances	100% Transmission Related	Transmission Plant Related	Transmission Labor Related	Total Included in Ratebase (E)+(F)+(G)	Explanation
19	1650001	Prepaid Insurance	443,712	-	-	443,712	-	443,712	Plant Related Insurance Policies
20	165000208	Prepaid Taxes	335,183	-	-	335,183	-	335,183	
21	1650004	Prepaid Interest	2,933	2,933	-	-	-	-	
22	1650009	Prepaid Carry Cost-Factored AR	73,044	73,044	-	-	-	-	AR Factoring - Retail Only
23	1650010	Prepaid Pension Benefits	17,051,597	-	-	-	17,051,597	17,051,597	Prefunded Pension Expense
24	1650014	FAS 158 Qual Contra Asset	(17,051,597)	(17,051,597)	-	-	-	-	SFAS 158 Offset
25	1650016	FAS 112 ASSETS	415,842	-	-	-	-	-	SFAS 112 Overfunding Asset
<b>Subtotal - Form 1, p 111.57.d</b>			<b>1,270,714</b>	<b>(16,559,778)</b>	<b>-</b>	<b>778,895</b>	<b>17,051,597</b>	<b>17,830,492</b>	

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet D Supporting IPP Credits  
 KENTUCKY POWER COMPANY

<u>Line Number</u>	<u>(A) Description</u>	<u>(B) 2009</u>
1	Net Funds from IPP Customers 12/31/2008 (2009 FORM 1, P269, line 15.b)	(228,221.00)
2	Interest Accrual (Company Records - Note 1)	(8,298.00)
3	Revenue Credits to Generators (Company Records - Note 1)	-
4	<u>Other Adjustments</u>	
5	Accounting Adjustment (Company Records - Note 1)	326.00
6		-
7	Net Funds from IPP Customers 12/31/2009 (2009 FORM 1, P269, line 24.f)	(236,193.00)
8	Average Balance for Year as Indicated in Column ((In 1 + In 7)/2)	(232,207.00)

Note 1 On this worksheet Company Records refers to KENTUCKY POWER COMPANY's general ledger.

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet E Supporting Revenue Credits  
 KENTUCKY POWER COMPANY

<u>Line Number</u>	<u>Description</u>	<u>Total Company</u>	<u>Non-Transmission</u>	<u>Transmission</u>
1	Account 450, Forfeited Discounts (FF1 p.300.16.(b); Company Records - Note 1)	1,780,498	1,780,498	-
2	Account 451, Miscellaneous Service Revenues (FF1 p.300.17.(b); Company Records - Note 1)	398,913	385,357	13,556
3	Account 454, Rent from Electric Property (FF1 p.300.19.(b); Company Records - Note 1)	4,600,609	4,588,984	11,625
4	Account 4560015, Associated Business Development - (Company Records - Note 1)	2,055,114	424,409	1,630,705
5	Account 456 - Other Electric Revenues - (Company Records - Note 1)	6,915,484	6,915,484	
6	<b>Subtotal - Other Operating Revenues (Company Total equals (FF1 p. 300.26.(b))</b>	<b>15,750,618</b>	<b>14,094,732</b>	<b>1,655,886</b>
7	Accounts 4470004 & 5, Revenues from Grandfathered Transmission Contracts - (Company Records - Note 1)	855,938	77,517	778,421
8	<b>Total Other Operating Revenues To Reduce Revenue Requirement</b>	<b>16,606,556</b>	<b>14,172,249</b>	<b>2,434,307</b>

Note 1 The total company data on this worksheet comes from the indicated FF1 source, or KENTUCKY POWER COMPANY's general ledger. The functional amounts identified as transmission revenue also come from the general ledger.

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet F Supporting Allocation of Specific O&M or A&G Expenses  
KENTUCKY POWER COMPANY

<u>Line Number</u>	<u>(A) Item No.</u>	<u>(B) Description</u>	<u>(C) 2009 Expense</u>	<u>(D) 100% Non-Transmission</u>	<u>(E) 100% Transmission Specific</u>	<u>(F) Explanation</u>
<b>Regulatory O&amp;M Deferrals &amp; Amortizations</b>						
1		No Applicable Charges for KPCO	-			
2			-			
3						
4		<b>Total</b>	<u>0</u>			
<b>Detail of Account 561 Per FERC Form 1</b>						
5	FF1 p 321.84.b	561 - Load Dispatching	0			
6	FF1 p 321.85.b	561.1 - Load Dispatch - Reliability	10,064			
7	FF1 p 321.86.b	561.2 - Load Dispatch - Monitor & Operate Trans System	752,594			
8	FF1 p 321.87.b	561.3 - Load Dispatch - Trans Service & Scheduling	1,666			
9	FF1 p 321.88.b	561.4 - Scheduling, System Control & Dispatch	1,089,485			
10	FF1 p 321.89.b	561.5 - Reliability, Planning and Standards Development	42,905			
11	FF1 p 321.90.b	561.6 - Transmission Service Studies	0			
12	FF1 p 321.91.b	561.7 - Generation Interconnection Studies	0			
13	FF1 p 321.92.b	561.8 - Reliability, Planning and Standards Development Servi	205,436			
14		<b>Total of Account 561</b>	<u>2,102,150</u>			
<b>Account 928</b>						
15	9280000	Regulatory Commission Exp	4	4		- N/A
16	9280001	Regulatory Commission Exp-Adm	57	57		- N/A
17	9280002	Regulatory Commission Exp-Case	(558)	(558)		-
18		<b>Total</b>	<u>(497)</u>	<u>(497)</u>		-
<b>Account 930.1</b>						
19	9301001	Newspaper Advertising Space	272,547	272,547		-
20	9301002	Radio Station Advertising Time	1,500	1,500		-
21	9301008	Direct Mail and Handouts	562	562		-
22	9301009	Fairs, Shows, and Exhibits	522	522		-
23	9301010	Publicity	1,126	1,126		-
24	9301011	Dedications, Tours, & Openings	11	11		-
25	9301012	Public Opinion Surveys	32,805	32,805		-
26	9301013	Movies Slide Films & Speeches	23,151	23,151		-
27	9301014	Video Communications	50	50		-
28	9301015	Other Corporate Comm Exp	66,630	66,630		-
29		<b>Total</b>	<u>398,904</u>	<u>398,904</u>		-
<b>Account 930.2</b>						
30	9302000	Misc General Expenses	161,479	161,479		
31	9302003	Corporate & Fiscal Expenses	28,091	28,091		
32	9302004	Research, Develop&Demonstr Exp	4,946	4,946		
33	9302005	Nucl Fac Ins - Replce Engy Cst	0	0		
34	9302007	Assoc Business Development Exp	313,102	229,807	83,295	
35		<b>Total</b>	<u>507,618</u>	<u>424,323</u>	<u>83,295</u>	

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet G Supporting - Development of Composite State Income Tax Rate  
 KENTUCKY POWER COMPANY

Formula Rate  
 KPCo WS G State Tax Rate  
 Page 22 of 34

Kentucky Corporate Income Tax	6.00%	
Apportionment Factor - Note 2	77.69%	
Effective State Tax Rate		4.66%
West Virginia Corporate Income Tax	8.50%	
Apportionment Factor - Note 2	2.73%	
Effective State Tax Rate		0.23%
Michigan Business Income Tax	6.04%	
Apportionment Factor - Note 2	0.00%	
Effective State Tax Rate		0.00%
State Income Tax Rate - Ohio	0.00%	
Phase-out Factor Note 1	0.00%	
Apportionment Factor - Note 2	6.75%	
Effective State Tax Rate		0.00%
Illinois Income Tax	7.30%	
Apportionment Factor - Note 2	0.55%	
Effective State Tax Rate		0.04%
Total Effective State Income Tax Rate		<u>4.93%</u>

Note 1 The Ohio State Income Tax is being phased-out prorata over a 5 year period from 2005 through 2009. The taxable portion of income is 0% in 2009. The phase-out factors can be found in the Ohio Revised Code at 5733.01(G)2(a)(v). This tax has been replaced with a Commercial Activities Tax that is included in Schedule H and H-1.

Note 2 Apportionment Factors are determined as part of the Company's annual tax return for that jurisdiction.

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet H Supporting Taxes Other than Income  
KENTUCKY POWER COMPANY

Line No.	(A) Account	(B) Total Company	(C) Property	(D) Labor	(E) Other	(F) Non-Allocable
		<b>NOTE 1</b>				
1	<b>Revenue Taxes</b>					
2	Gross Receipts Tax	206,405				206,405
3	<b>Real Estate and Personal Property Taxes</b>					
4	Real and Personal Property - Kentucky	9,616,458	9,616,458			
5	Real and Personal Property - Other	3,254	3,254			
6	<b>Payroll Taxes</b>					
7	Federal Insurance Contribution (FICA)	1,631,366		1,631,366		
8	Federal Unemployment Tax	5,717		5,717		
9	State Unemployment Insurance	18,523		18,523		
10	<b>Production Taxes</b>					
11	State Severance Taxes	-				-
12	<b>Miscellaneous Taxes</b>					
13	State Business & Occupation Tax	-				-
14	State Public Service Commission Fees	710,060			710,060	
15	State Franchise Taxes	68,465			68,465	
16	State Lic/Registration Fee	95			95	
17	Misc. State and Local Tax	230			230	
18	Sales & Use	(582,273)				(582,273)
19	Federal Excise Tax	4,262				4,262
20	Michigan Single Business Tax	-				-
21	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	11,682,562	9,619,712	1,655,606	778,850	(371,606)

NOTE 1: The detail of each total company number and its source in the FERC Form 1 is shown on WS H-1.

**Functional Property Tax Allocation**

	Production	Transmission	Distribution	General	Total	
22	Functionalized Net Plant (Hist. TCOS, Lns 212 thru 222)	311,390,888	296,964,992	428,782,699	26,765,990	1,063,904,569
	<b>KENTUCKY JURISDICTION</b>					
23	Percentage of Plant in KENTUCKY JURISDICTION	100.00%	100.00%	100.00%	100.00%	
24	Net Plant in KENTUCKY JURISDICTION (Ln 22 * Ln 23)	311,390,888	296,964,992	428,782,699	26,765,990	1,063,904,569
25	Less: Net Value of Exempted Generation Plant	120,217,738				
26	Taxable Property Basis (Ln 24 - Ln 25)	191,173,150	296,964,992	428,782,699	26,765,990	943,686,831
27	Relative Valuation Factor	33%	100%	100%	100%	3.3334
28	Weighted Net Plant (Ln 26 * Ln 27)	63,737,128	296,964,992	428,782,699	26,765,990	
29	General Plant Allocator (Ln 28 / (Total - General Plant))	8.07%	37.62%	54.31%	-100.00%	
30	Functionalized General Plant (Ln 29 * General Plant)	2,160,887	10,068,038	14,537,067	(26,765,990)	-
31	Weighted KENTUCKY JURISDICTION Plant (Ln 28 + 30)	65,898,015	307,033,030	443,319,766	-	816,250,808
32	Functional Percentage (Ln 31/Total Ln 31)	8.07%	37.62%	54.31%		
33	Functionalized Expense in KENTUCKY JURISDICTION	776,361	3,617,234	5,222,863		9,616,458
34	Total Other Jurisdictions: (Line 5 * Net Plant Allocator)		913			3,254
35	Total Func. Property Taxes (Sum Lns 33, 34)	776,361	3,618,147	5,222,863		9,619,712

AEP East Companies  
 Cost of Service Formula Rate Using 2008 FF1 Balances  
 Worksheet H-1 Form 1 Source Reference of Company Amounts on WS H  
 KENTUCKY POWER COMPANY

Line No.	(A) Annual Tax Expenses by Type (Note 1)	(B) Total Company	(C) FERC FORM 1 Tie-Back	(D) FERC FORM 1 Reference
1	<b>Revenue Taxes</b>			
2	Gross Receipts Tax	206,405	(16,746)	P.263.1 ln 27 (i)
			223,151	P.263.1 ln 28 (i)
3	<b>Real Estate and Personal Property Taxes</b>			
4	Real and Personal Property - Kentucky	9,616,458	1,815	P.263 ln 30 (i)
			(11,197)	P.263 ln 31 (i)
			855,411	P.263 ln 32 (i)
			8,714,874	P.263 ln 33 (i)
			22	P.263 ln 35 (i)
			(790)	P.263 ln 36 (i)
			45,167	P.263 ln 37 (i)
			(864)	P.263 ln 38 (i)
			12,020	P.263 ln 39 (i)
5	Real and Personal Property - Other	3,254	1,061	P.263.1 ln 11 (i)
			1,042	P.263.1 ln 12 (i)
			82	P.263.1 ln 13 (i)
			871	P.263.1 ln 14 (i)
			198	P.263.1 ln 35 (i)
6	<b>Payroll Taxes</b>			
7	Federal Insurance Contribution (FICA )	1,631,366	1,631,366	P.263 ln 4 (i)
8	Federal Unemployment Tax	5,717	5,717	P.263 ln 5 (i)
9	State Unemployment Insurance	18,523	19,069	P.263 ln 21 (i)
			(546)	P.263.1 ln 17 (i)
10	<b>Production Taxes</b>			
11	State Severance Taxes	-	-	
12	<b>Miscellaneous Taxes</b>			
13	State Business & Occupation Tax	-	-	
14	State Public Service Commission Fees	710,060	335,183	P.263 ln 23 (i)
			374,877	P.263 ln 24 (i)
15	State Franchise Taxes	68,465	(5,085)	P.263.1 ln 5 (i)
			54,700	P.263.1 ln 6 (i)
			18,850	P.263.1 ln 23 (i)
16	State Lic/Registration Fee	95	55	P.263.1 ln 15 (i)
			40	P.263.1 ln 36 (i)
17	Misc. State and Local Tax	230	230	P.263 ln 19 (i)
18	Sales & Use	(582,273)	1,808	P.263 ln 26 (i)
			15,045	P.263 ln 27 (i)
			(599,126)	P.263 ln 28 (i)
19	Federal Excise Tax	4,262	4,262	P.263 ln 7 (i)
20	Michigan Single Business Tax	-	-	
21	Total Taxes by Allocable Basis (Total Company Amount Ties to FFI p.114, Ln 14,(c))	11,682,562	11,682,562	

Note 1: The taxes assessed on each operating company can differ from year to year and between operating companies by both the type of taxes and the states in which they were assessed. Therefore, for each company, the types and jurisdictions of tax expense recorded on this page could differ from the same page in the same company's prior year template or from this page in other operating companies' current year templates. For each update, this sheet will be revised to ensure that the total activity recorded hereon equals the total reported in account 408.1 on P. 114, Ln 14 of the Ferc Form 1.

**AEP East Companies**  
**Cost of Service Formula Rate Using 2009 FF1 Balances**  
**Worksheet I Supporting Transmission Plant in Service Additions**  
**KENTUCKY POWER COMPANY**

(A) (B) (C) (D) (E) (F) (G) (H) (I)

**I. Calculation of Composite Depreciation Rate**

1	Transmission Plant @ Beginning of Historic Period (2009) (P.206, In 58,(b)):	431,804,417
2	Transmission Plant @ End of Historic Period (2009) (P.207, In 58,(g)):	438,744,866
3		<u>870,549,283</u>
4	Average Balance of Transmission Investment	435,274,642
5	Annual Depreciation Expense, Historic TCOS, In 276	7,420,678
6	Composite Depreciation Rate	1.70%
7	Round to 1.7% to Reflect a Composite Life of 59 Years	1.70%

**II. Calculation of Property Placed in Service by Month and the Related Depreciation Expense**

8	Month in Service	Capitalized Balance	Composite Annual Depreciation Rate	Annual Depreciation	Monthly Depreciation	No. Months Depreciation	First Year Depreciation Expense
9	January	\$ 1,357,552	1.70%	\$ 23,078	\$ 1,923	11	\$ 21,153
10	February	\$ 1,347,974	1.70%	\$ 22,916	\$ 1,910	10	\$ 19,100
11	March	\$ 1,386,470	1.70%	\$ 23,570	\$ 1,964	9	\$ 17,676
12	April	\$ 1,365,622	1.70%	\$ 23,216	\$ 1,935	8	\$ 15,480
13	May	\$ 1,347,919	1.70%	\$ 22,915	\$ 1,910	7	\$ 13,370
14	June	\$ 1,384,118	1.70%	\$ 23,530	\$ 1,961	6	\$ 11,766
15	July	\$ 1,366,019	1.70%	\$ 23,222	\$ 1,935	5	\$ 9,675
16	August	\$ 1,383,604	1.70%	\$ 23,521	\$ 1,960	4	\$ 7,840
17	September	\$ 1,373,871	1.70%	\$ 23,356	\$ 1,946	3	\$ 5,838
18	October	\$ 1,367,546	1.70%	\$ 23,248	\$ 1,937	2	\$ 3,874
19	November	\$ 1,335,391	1.70%	\$ 22,702	\$ 1,892	1	\$ 1,892
20	December	\$ 3,824,251	1.70%	\$ 65,012	\$ 5,418	0	\$ -
21	Investment	<u>\$ 18,840,335</u>				Depreciation Expense	<u>\$ 127,664</u>

**III. Plant Transferred**

22	\$ -	<== This input area is for original cost plant
23	\$ -	<== This input area is for accumulated depreciation that may be associated with capital expenditures. It would have an impact if a company had assets transferred from a subsidiary.
24 (Ln 7 * Ln 22)	\$ -	<== This input area is for additional Depreciation Expense

**IV. List of Major Projects Expected to be In-Service in 2010**

	<u>Estimated Cost</u> <u>(000's)</u>	<u>Month in Service</u>
25 <b>Major Zonal Projects</b>		
26 N/A	\$0	Multiple
27	<u>Subtotal</u>	\$0
28 <b>PJM Socialized/Beneficiary Allocated Regional Projects</b>		
29 N/A	\$0	
30	<u>Subtotal</u>	\$0

AEP East Companies  
Cost of Service Formula Rate Using 2009 FF1 Balances  
Worksheet J Supporting Calculation of PROJECTED PJM RTEP Project Revenue Requirement Billed to Benefiting Zones  
KENTUCKY POWER COMPANY

**I. Calculate Return and Income Taxes with basis point ROE increase for Projects Qualified for Regional Billing.**

**A. Determine 'R' with hypothetical basis point increase in ROE for Identified Projects**

ROE w/o incentives (Projected TCOS, In 164)			11.49%
Project ROE Incentive Adder			<=ROE Adder Cannot Exceed 125 Basis Points
ROE with additional basis point incentive			11.49% <= ROE Including Incentives Cannot Exceed 12.74% Until July 1, 2012
Determine R ( cost of long term debt, cost of preferred stock and equity percentage is from the Projected TCOS, Ins 162 through164)			
	%	Cost	Weighted cost
Long Term Debt	55.99%	6.46%	3.618%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	44.01%	11.49%	<u>5.057%</u>
		R =	8.675%

SUMMARY OF PROJECTED ANNUAL RTEP REVENUE REQUIREMENTS			
	Rev Require	W Incentives	Incentive Amounts
PROJECTED YEAR	2010	-	- \$ -

**B. Determine Return using 'R' with hypothetical basis point ROE increase for Identified Projects.**

Rate Base (Projected TCOS, In 78)	266,897,848
R (from A. above)	8.675%
Return (Rate Base x R)	23,153,003

**C. Determine Income Taxes using Return with hypothetical basis point ROE increase for Identified Projects.**

Return (from B. above)	23,153,003
Effective Tax Rate (Projected TCOS, In 126)	36.04%
Income Tax Calculation (Return x CIT)	8,344,714
ITC Adjustment	(373,022)
Income Taxes	7,971,692

**II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical basis point ROE increase.**

**A. Determine Annual Revenue Requirement less return and Income Taxes.**

Annual Revenue Requirement (Projected TCOS, In 1)	41,178,105
T.E.A. & Lease Payments (Projected TCOS, Lns 105 & 106)	(8,835,297)
Return (Projected TCOS, In 134)	23,153,003
Income Taxes (Projected TCOS, In 133)	<u>7,971,692</u>
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	18,888,708

**B. Determine Annual Revenue Requirement with hypothetical basis point increase in ROE.**

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	18,888,708
Return (from I.B. above)	23,153,003
Income Taxes (from I.C. above)	<u>7,971,692</u>
Annual Revenue Requirement, with Basis Point ROE increase	50,013,402
Depreciation (Projected TCOS, In 111)	<u>7,390,213</u>
Annual Rev. Req, w/ Basis Point ROE increase, less Depreciation	42,623,189

**C. Determine FCR with hypothetical basis point ROE increase.**

Net Transmission Plant (Projected TCOS, In 48)	295,941,682
Annual Revenue Requirement, with Basis Point ROE increase	50,013,402
FCR with Basis Point increase in ROE	16.90%
Annual Rev. Req, w/ Basis Point ROE increase, less Dep.	42,623,189
FCR with Basis Point ROE increase, less Depreciation	14.40%
FCR less Depreciation (Projected TCOS, In 9)	<u>13.83%</u>
Incremental FCR with Basis Point ROE increase, less Depreciation	0.57%

**III. Calculation of Composite Depreciation Rate**

Transmission Plant @ Beginning of Historic Period (2009) (P.206, In 58,(b)):	431,804,417
Transmission Plant @ End of Historic Period (2009) (P.207, In 58,(g)):	<u>438,744,866</u>
Subtotal	870,549,283
Average Transmission Plant Balance for 2009	435,274,642
Annual Depreciation Rate (Projected TCOS, In 111)	7,420,678
Composite Depreciation Rate	1.70%
Depreciable Life for Composite Depreciation Rate	58.66
Round to nearest whole year	59



AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet K Supporting Calculation of TRUE-UP PJM RTEP Project Revenue Requirement Billed to Benefiting Zones  
 KENTUCKY POWER COMPANY

**I. Calculate Return and Income Taxes with 0 basis point ROE increase for Projects Qualified for Regional Billing.**

**A. Determine 'R' with hypothetical 0 basis point increase in ROE for Identified Projects**

ROE w/o incentives (True-Up TCOS, In 164)			11.49%
Project ROE Incentive Adder		0	<=ROE Adder Cannot Exceed 100 Basis Points
ROE with additional 0 basis point incentive			11.49% <= ROE Including Incentives Cannot Exceed 12.5% Until July 1, 2012
Determine R (cost of long term debt, cost of preferred stock and equity percentage is from the True-Up TCOS, Ins 162 through 164)			
	%	Cost	Weighted cost
Long Term Debt	53.88%	6.35%	3.423%
Preferred Stock	0.00%	0.00%	0.000%
Common Stock	46.12%	11.49%	5.299%
		R =	8.722%

SUMMARY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS FOR RTEPPROJECTS			
TRUE-UP YEAR	2009	Rev Require	Incentive Amounts
As Projected in Prior Year WS J			\$ -
Actual after True-up	\$ -	\$ -	\$ -
True-up of ARR For 2009	-	-	-

**B. Determine Return using 'R' with hypothetical 0 basis point ROE increase for Identified Projects.**

Rate Base (True-Up TCOS, In 78)	257,742,156
R (from A. above)	8.722%
Return (Rate Base x R)	22,481,398

**C. Determine Income Taxes using Return with hypothetical 0 basis point ROE increase for Identified Projects.**

Return (from B. above)	22,481,398
Effective Tax Rate (True-Up TCOS, In 126)	37.56%
Income Tax Calculation (Return x CIT)	8,444,284
ITC Adjustment	(377,897)
Income Taxes	8,066,387

**II. Calculate Net Plant Carrying Charge Rate (Fixed Charge Rate or FCR) with hypothetical 0 basis point ROE increase.**

**A. Determine Annual Revenue Requirement less return and Income Taxes.**

Annual Revenue Requirement (True-Up TCOS, In 1)	40,476,610
T.E.A. & Lease Payments (True-Up TCOS, Lns 105 & 106)	(8,835,297)
Return (True-Up TCOS, In 134)	22,481,398
Income Taxes (True-Up TCOS, In 133)	<u>8,066,387</u>
Annual Revenue Requirement, Less TEA Charges, Return and Taxes	18,764,123

**B. Determine Annual Revenue Requirement with hypothetical 0 basis point increase in ROE.**

Annual Revenue Requirement, Less TEA Charges, Return and Taxes	18,764,123
Return (from I.B. above)	22,481,398
Income Taxes (from I.C. above)	<u>8,066,387</u>
Annual Revenue Requirement, with 0 Basis Point ROE increase	49,311,907
Depreciation (True-Up TCOS, In 111)	<u>7,390,203</u>
Annual Rev. Req. w/ 0 Basis Point ROE increase, less Depreciation	41,921,705

**C. Determine FCR with hypothetical 0 basis point ROE increase.**

Net Transmission Plant (True-Up TCOS, In 48)	295,620,104
Annual Revenue Requirement, with 0 Basis Point ROE increase	49,311,907
FCR with 0 Basis Point increase in ROE	16.68%
Annual Rev. Req. w / 0 Basis Point ROE increase, less Dep.	41,921,705
FCR with 0 Basis Point ROE increase, less Depreciation	14.18%
FCR less Depreciation (True-Up TCOS, In 9)	<u>14.18%</u>
Incremental FCR with 0 Basis Point ROE increase, less Depreciation	0.00%

**III. Calculation of Composite Depreciation Rate**

Transmission Plant @ Beginning of Historic Period (P.206, In 58.(b)):	431,804,417
Transmission Plant @ End of Historic Period (P.207, In 58.(g)):	<u>438,744,866</u>
Subtotal	870,549,283
Average Transmission Plant Balance for	435,274,642
Annual Depreciation Rate (True-Up TCOS, In 111)	7,420,678
Composite Depreciation Rate	1.70%
Depreciable Life for Composite Depreciation Rate	58.66
Round to nearest whole year	59

KPCo Worksheet K - ATRR TRUE-UP Calculation for PJM Projects Charged to Benefiting Zones

IV. Determine the Revenue Requirement, and Additional Revenue Requirement for facilities receiving incentives.

A. Base Plan Facilities

Facilities receiving incentives accepted by FERC in Docket No. [REDACTED] (e.g. ER05-925-000)

Project Description:

2009	Rev Require	W Incentives	Incentive Amounts
Prior Yr Projected	-	-	-
Prior Yr True-Up	-	-	-
True-Up Adjustment	-	-	-

Details		Current Year	2009
Investment Year (yyyy)	2008	ROE increase accepted by FERC (Basis Points)	-
Service Month (1-12)		FCR w/o incentives, less depreciation	14.18%
Useful life	59	FCR w/incentives approved for these facilities, less dep.	14.18%
CIAC (Yes or No)	No	Annual Depreciation Expense	-

**TRUE UP OF PROJECT REVENUE REQUIREMENT FOR PRIOR YEAR:**  
 CUMULATIVE HISTORY OF TRUED-UP ANNUAL REVENUE REQUIREMENTS:  
 INPUT TRUE-UP ARR (WITH & WITHOUT INCENTIVES) FROM EACH PRIOR YEAR  
 TEMPLATE BELOW TO MAINTAIN HISTORY OF TRUED-UP ARRS OVER THE  
 LIFE OF THE PROJECT.

Investment Year	Beginning Balance	Depreciation Expense	Ending Balance	Average Balance	RTEP Rev. Req't. w/o Incentives	RTEP Rev. Req't. with Incentives **	Incentive Rev. Requirement ##	RTEP Projected Rev. Req't. From Prior Year WS J w/o Incentives	RTEP Rev Req't True-up w/o Incentives	RTEP Projected Rev. Req't. From Prior Year WS J with Incentives **	RTEP Rev Req't True-up with Incentives **	True-up of Incentive with Incentives **
2008	-	-	-	-	-	-	\$ -					
2009	-	-	-	-	-	-	\$ -					
2010	-	-	-	-	-	-	\$ -					
2011	-	-	-	-	-	-	\$ -					
2012	-	-	-	-	-	-	\$ -					
2013	-	-	-	-	-	-	\$ -					
2014	-	-	-	-	-	-	\$ -					
2015	-	-	-	-	-	-	\$ -					
2016	-	-	-	-	-	-	\$ -					
2017	-	-	-	-	-	-	\$ -					
2018	-	-	-	-	-	-	\$ -					
2019	-	-	-	-	-	-	\$ -					
2020	-	-	-	-	-	-	\$ -					
2021	-	-	-	-	-	-	\$ -					
2022	-	-	-	-	-	-	\$ -					
2023	-	-	-	-	-	-	\$ -					
2024	-	-	-	-	-	-	\$ -					
2025	-	-	-	-	-	-	\$ -					
2026	-	-	-	-	-	-	\$ -					
2027	-	-	-	-	-	-	\$ -					
2028	-	-	-	-	-	-	\$ -					
2029	-	-	-	-	-	-	\$ -					
2030	-	-	-	-	-	-	\$ -					
2031	-	-	-	-	-	-	\$ -					
2032	-	-	-	-	-	-	\$ -					
2033	-	-	-	-	-	-	\$ -					
2034	-	-	-	-	-	-	\$ -					
2035	-	-	-	-	-	-	\$ -					
2036	-	-	-	-	-	-	\$ -					
2037	-	-	-	-	-	-	\$ -					
2038	-	-	-	-	-	-	\$ -					
2039	-	-	-	-	-	-	\$ -					
2040	-	-	-	-	-	-	\$ -					
2041	-	-	-	-	-	-	\$ -					
2042	-	-	-	-	-	-	\$ -					
2043	-	-	-	-	-	-	\$ -					
2044	-	-	-	-	-	-	\$ -					
2045	-	-	-	-	-	-	\$ -					
2046	-	-	-	-	-	-	\$ -					
2047	-	-	-	-	-	-	\$ -					
2048	-	-	-	-	-	-	\$ -					
2049	-	-	-	-	-	-	\$ -					
2050	-	-	-	-	-	-	\$ -					
2051	-	-	-	-	-	-	\$ -					
2052	-	-	-	-	-	-	\$ -					
2053	-	-	-	-	-	-	\$ -					
2054	-	-	-	-	-	-	\$ -					
2055	-	-	-	-	-	-	\$ -					
2056	-	-	-	-	-	-	\$ -					
2057	-	-	-	-	-	-	\$ -					
2058	-	-	-	-	-	-	\$ -					
2059	-	-	-	-	-	-	\$ -					
2060	-	-	-	-	-	-	\$ -					
2061	-	-	-	-	-	-	\$ -					
2062	-	-	-	-	-	-	\$ -					
2063	-	-	-	-	-	-	\$ -					
2064	-	-	-	-	-	-	\$ -					
2065	-	-	-	-	-	-	\$ -					
2066	-	-	-	-	-	-	\$ -					
2067	-	-	-	-	-	-	\$ -					
Project Totals	-	-	-	-	-	-	\$ -					

\*\* This is the total amount that needs to be reported to PJM for billing to all regions.

## This is the calculation of additional incentive revenue on projects deemed by the FERC to be eligible for an incentive return. This additional incentive requirement is applicable for the life of this specific project. Each year the revenue requirement calculated for PJM should be incremented by the amount of the incentive revenue calculated for that year on this project.

AEP East Companies  
 Cost of Service Formula Rate Using 2009 FF1 Balances  
 Worksheet L Supporting Projected Cost of Debt  
 KENTUCKY POWER COMPANY

**Calculation of Projected Interest Expense Based on Outstanding Debt at Year End**

<u>Line Number</u>	<u>(A) Issuance</u>	<u>(B) Principle Outstanding</u>	<u>(C) Interest Rate</u>	<u>(D) Annual Expense (See Note S on Projected Template)</u>	<u>(E) Notes</u>
1	<b>Long Term Debt (FF1.p. 256-257.h)</b>				
2	Notes Payable to Parent	20,000,000	5.250%	1,050,000	
3					
4	<b>Installment Purchase Contracts (FF1.p. 256-257.h, a)</b>				
5	Senior Unsecured Notes - Series D	75,000,000	5.625%	4,218,750	
6	Senior Unsecured Notes - Series E	325,000,000	6.000%	19,500,000	
7	Senior Unsecured Notes - 7.250%	40,000,000	7.250%	2,900,000	
8	Senior Unsecured Notes - 8.030%	30,000,000	8.030%	2,409,000	
9	Senior Unsecured Notes - 8.130%	60,000,000	8.130%	4,878,000	
10				-	
11				-	
12				-	
13				-	
14				-	
15				-	
16				-	
17				-	
18				-	
19				-	
20				-	
21				-	
22				-	
23				-	
24				-	
25				-	
26				-	
27	<b>Issuance Discount, Premium, &amp; Expenses:</b>				
28	Auction Fees	FF1.p. 256 & 257.Lines Described as Fees		-	
29	Allowable Hedge Amortization (See Ln 45 Below)			92,956	
30	Amort of Debt Discount and Expenses	FF1.p. 117.63.c		457,098	
31	Amort of Debt Premiums (Enter Negative)	FF1.p. 117.65.c		-	
32	<b>Reacquired Debt:</b>				
33	Amortization of Loss	FF1.p. 117.64.c		33,649	
34	Amortization of Gain	FF1.p. 117.66.c		-	
35	<b>Total Interest on Long Term Debt</b>	550,000,000	6.46%	35,539,453	
36	<b>Preferred Stock (FF1.p. 250-251)</b>				
37		<b>Preferred Shares Outstanding</b>			
38		-	0.00%	-	
39				-	
40	<b>Dividends on Preferred Stock</b>	-		-	
41	<b>Net Total Hedge Gains and Losses (WS M, Ln 35, (E))</b>			92,956	
42	<b>Total Projected Capital Structure Balance for 2010 (Projected TCOS, Ln 165)</b>			982,384,639	
43	<b>Financial Hedge Recovery Limit - Five Basis Points of Total Capital</b>			0.0005	
44	<b>Limit of Recoverable Amount</b>			491,192	
45	<b>Recoverable Hedge Amortization (Lesser of Ln 41 or Ln 44)</b>			<b>92,956</b>	

AEP East Companies  
Transmission Cost of Service Formula Rate  
KENTUCKY POWER COMPANY

**Worksheet M Supporting Calculation of Capital Structure and Weighted Average Cost of Capital Based on Average of Balances At 12/31/2008 & 12/31/2009**

(A)	(B)	(C)	(D)	(E)
Line		Balances @ 12/31/2009	Balances @ 12/31/2008	Average
<b>Development of Average Balance of Common Equity</b>				
1	Proprietary Capital (112.16.c&d)	431,783,697	398,008,673	414,896,185
2	Less Preferred Stock (Ln 55 Below)	0	-	-
3	Less Account 216.1 (112.12.c&d)	0	0	0
4	Less Account 219.1 (112.15.c&d)	-600,942	59,584	-270,679
5	<b>Average Balance of Common Equity</b>	<b>432,384,639</b>	<b>397,949,089</b>	<b>415,166,864</b>

**Development of Cost of Long Term Debt Based on Average Outstanding Balance**

6	Bonds (112.18.c&d)	0	0	0
7	Less: Reacquired Bonds (112.19.c&d)	0	0	0
8	LT Advances from Assoc. Companies (112.20.c&d)	20,000,000	20,000,000	20,000,000
9	Senior Unsecured Notes (112.21.c&d)	530,000,000	400,000,000	465,000,000
10	Less: Fair Value Hedges (See Note on Ln 12 below)	0	0	0
11	<b>Total Average Debt</b>	<b>550,000,000</b>	<b>420,000,000</b>	<b>485,000,000</b>

12 **NOTE: The balance of fair value hedges on outstanding long term debt are to be excluded from the balance of long term debt included in the formula's capital structure. (Column H of the FF1)**

**13 Annual Interest Expense for 2009**

14	Interest on Long Term Debt (256-257.33.i)			30,323,070
15	Less: Total Hedge Gain/Expense Accumulated from p 256-257, col. (i) of FERC Form 1 included in Ln 14 and shown in Ln 34 below.			92,956
16	Plus: Allowed Hedge Recovery From Ln 39 below.			92,956
17	Amort of Debt Discount & Expense (117.63.c)			457,098
18	Amort of Loss on Reacquired Debt (117.64.c)			33,649
19	Less: Amort of Premium on Debt (117.65.c)			-
20	Less: Amort of Gain on Reacquired Debt (117.66.c)			-
21	<b>Total Interest Expense (Ln 14 + Ln 17 + Ln 18 - Ln 19 - Ln 20)</b>			<b>30,813,817</b>

22 **Average Cost of Debt for 2009 (Ln 21/Ln 11)**

**6.35%**

**CALCULATION OF RECOVERABLE HEDGE GAINS/LOSSES**

23 **NOTE: The net amount of hedging gains or losses recorded in account 427 to be recovered in this formula rate should be limited to the effective portion of pre-issuance cash flow hedges that are amortized over the life of the underlying debt issuances. The recovery of a net loss or passback of a net gain will be limited to five basis points of the total Capital Structure. Amounts related to the ineffective portion of pre-issuance hedges, cash settlements of fair value hedges issued on Long Term Debt, post-issuance cash flow hedges, and cash flow hedges of variable rate debt issuances are not recoverable in this formula and are to be recorded in the "Excludable" column below.**

HEDGE AMOUNTS BY ISSUANCE (FROM p. 256-257 (i) of the FERC Form 1)	Total Hedge (Gain)/Loss for 2009	Less Excludable Amounts (See NOTE on Line 23)	Net Includable Hedge Amount	Amortization Period		
				Remaining Unamortized Balance	Beginning	Ending
24 Senior Unsecured Notes - Series E	92,956	-	92,956	712,664	September 2007	September 2017
25 Senior Unsecured Notes	0	-	-			
26 Senior Unsecured Notes	0	-	-			
27 Senior Unsecured Notes	0	-	-			
28 Senior Unsecured Notes	0	-	-			
29 Senior Unsecured Notes	0	-	-			
30 Senior Unsecured Notes	0	-	-			
31 Senior Unsecured Notes	0	-	-			
32 Senior Unsecured Notes	0	-	-			
33 Senior Unsecured Notes	0	-	-			
34 Total Hedge Amortization	92,956	-	-			
35 Hedge Gain or Loss Prior to Application of Recovery Limit (Sum of Lines 24 to 33)			92,956			
36 Total Average Capital Structure Balance for 2009 (True-UP TCOS, Ln 165)			900,166,864			
37 Financial Hedge Recovery Limit - Five Basis Points of Total Capital			0.0005			
38 Limit of Recoverable Amount			450,083			
39 <b>Recoverable Hedge Amortization (Lesser of Ln 35 or Ln 38)</b>			<b>92,956</b>			

**Development of Cost of Preferred Stock**

Preferred Stock			Average
40 0% Series - 0 - Dividend Rate (p. 250-251. 7 & 10.a)	0.00%	0.00%	
41 0% Series - 0 - Par Value (p. 250-251. 8.c)	\$ -	\$ -	
42 0% Series - 0 - Shares O/S (p.250-251. 8 & 11.e)	-	-	
43 0% Series - 0 - Monetary Value (Ln 41 * Ln 42)	-	-	
44 0% Series - 0 - Dividend Amount (Ln 40 * Ln 43)	-	-	
45 0% Series - - Dividend Rate (p. 250-251.a)			
46 0% Series - - Par Value (p. 250-251.c)			
47 0% Series - - Shares O/S (p.250-251. e)			
48 0% Series - - Monetary Value (Ln 46 * Ln 47)			
49 0% Series - - Dividend Amount (Ln 45 * Ln 48)			
50 0% Series - - Dividend Rate (p. 250-251.a)			
51 0% Series - - Par Value (p. 250-251.c)			
52 0% Series - - Shares O/S (p.250-251.e)			
53 0% Series - - Monetary Value (Ln 51 * Ln 52)			
54 0% Series - - Dividend Amount (Ln 50 * Ln 53)			
55 <b>Balance of Preferred Stock (Lns 43, 48, 53)</b>	-	-	-
56 <b>Dividends on Preferred Stock (Lns 44, 49, 54)</b>	-	-	-
57 <b>Average Cost of Preferred Stock (Ln 56/55)</b>	0.00%	0.00%	

Year End Total Agrees to FF1 p.112, Ln 3, col (c) & (d)

**AEP East Companies**  
**Cost of Service Formula Rate Using 2009 FF1 Balances**  
**Worksheet N - Gains (Losses) on Sales of Plant Held For Future Use**  
**KENTUCKY POWER COMPANY**

Note: Gain or loss on plant held for future use are recorded in accounts 411.6 or 411.7 respectively. Sales will be functionalized based on the description of that asset. Sales of transmission assets will be direct assigned; sales of general assets will be functionalized on labor. Sales of plant held for future use related to generation or distribution will not be included in the formula.

Line	(A) Date	(B) Property Description	(C) Function (T) or (G) T = Transmission G = General	(D) Basis	(E) Proceeds	(F) (Gain) / Loss	(G) Functional Allocator	(H) Functionalized Proceeds (Gain) / Loss	(I) FERC Account
1						-	0.000%	-	
2						-	0.000%	-	
3						-	0.000%	-	
4					Net (Gain) or Loss for 2009	- =====		- =====	

AEP East Companies  
Cost of Service Formula Rate Using 2008 FF1 Balances  
Worksheet O - Calculation of Postemployment Benefits Other than Pensions Expenses Allocable to Transmission Service  
KENTUCKY POWER COMPANY

Total AEP East Operating Company PBOP Settlement Amount 48,100,000

**Allocation of PBOP Settlement Amount for 2008:**

Total Company Amount

Line#	Company	Actual Expense (Including AEPSC Billed OPEB)	Ratio of Company Actual to Total	Allocation of PBOB Recovery Allowance	Labor Allocator for 2008	Actual Expense	Allowable Expense	One Year Functional Expense (Over)/Under
		(A)	(B)=(A)/Total (A)	(C)=(B) * 48100000	(D)	(E)=(A) * (D)	(F)=(C) * (D)	(G)=(E) - (F)
		(Line 14)						
1	APCo	18,441,517	29.26%	14,073,264	7.028%	1,296,063	989,064	306,999
2	CSP	10,281,860	16.31%	7,846,390	4.162%	427,913	326,553	101,360
3	I&M	12,473,804	19.79%	9,519,127	4.127%	514,802	392,861	121,941
4	KPCo	3,529,520	5.60%	2,693,481	8.595%	303,351	231,496	71,855
5	KNGP	544,295	0.86%	415,367	11.148%	60,678	46,305	14,373
6	OPCo	17,102,723	27.13%	13,051,591	7.326%	1,252,955	956,167	296,788
7	WPCo	656,219	1.04%	500,780	4.102%	26,916	20,540	6,376
8	<b>Sum of Lines 1 to 7</b>	63,029,939		48,100,000		3,882,678	2,962,986	919,692

**Detail of Actual PBOP Expenses to be Removed in Cost of Service**

	APCo	CSP	I&M	KPCo	KNGSPT	OPCo	WPCo	AEP East Total
9 Direct Charged PBOP Expense per Actuarial Report	25,117,708	11,854,216	19,543,777	4,099,566	620,366	20,108,946	765,967	82,110,546
10 Additional PBOP Ledger Entries (from Company Records)	(3,087,412)	24,390	(4,186,450)	(1)	-	(210,679)	-	
11 Medicare Subsidy	(5,206,873)	(2,393,921)	(4,008,620)	(867,380)	(123,297)	(4,175,705)	(152,317)	(16,928,113)
12 Net Company Expense (Ln 9 + Ln 10 + Ln 11)	16,823,423	9,484,685	11,348,707	3,232,185	497,069	15,722,562	613,650	57,722,281
13 PBOP Expenses From AEP Service Corporation (from Company Records)	1,618,094	797,175	1,125,097	297,335	47,226	1,380,161	42,569	5,307,658
14 Company PBOP Expense (Ln 12 + Ln 13)	18,441,517	10,281,860	12,473,804	3,529,520	544,295	17,102,723	656,219	63,029,939

AEP EAST COMPANIES  
 PJM FORMULA RATE  
 WORKSHEET P - TRANSMISSION DEPRECIATION RATES  
 EFFECTIVE AS OF 1/1/2009  
 FOR SINGLE JURISDICTION COMPANIES  
 KENTUCKY POWER COMPANY

	<b>PLANT ACCT.</b>	<b>RATES Note 1</b>
<b><i>TRANSMISSION PLANT</i></b>		
Structures & Improvements	352.0	1.71%
Station Equipment	353.0	1.71%
Towers & Fixtures	354.0	1.71%
Poles & Fixtures	355.0	1.71%
Overhead Conductors	356.0	1.71%
Underground Conduit	357.0	1.71%
Underground Conductors	358.0	1.71%
Trails & Roads	359.0	1.71%

Reference:

Note 1: Rates Approved in Kentucky Public Service Commission Case No. 91-066.

**General Note**

Per the terms of the settlement in this case, AEP will make a 205 filing whenever a company's rates are changed by their commission(s), or if the methodology to calculate the jurisdictional allocator in multiple-state companies changes. Changes in the allocation factors will not necessitate a 205 filing.